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Volume 62, Number 12
December 1984

09825 1957257 W 3 2025
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4520 EAST WEST HWY STE 800
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Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

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Brazilian hydro plant dedicated

Power from the massive 12,600-MW Itaipu hydroelectric project is now moving to Brazilian load centers via a ±600-kv d-c transmission system designed and built by ASEA of Sweden following dedication of the jointly owned project by President Figueredo of Brazil and President Stroessner of Paraguay on October 25. Paraguay's share of the output, generated at 50 Hz, is excess to the country's needs and is being used by Brazil under a long-term agreement. After conversion to d-c at the convertor station at Foz do Iguacu, near the dam, the power is sent 800 km to an invertor station near the industrial center of Sao Paulo, where it is changed to 60-Hz a-c power and is transmitted at 345-kV for use in Southeastern Brazil. Brazil's share of the Itaipu power, generated at 60 Hz, is sent to Sao Paulo via three 750-kV series compensated a-c transmission lines. Shown above are incoming 500-kV lines to the convertor station at Foz do Iguacu.

EPA-driven audits, citizen suits mandate stricter environmental compliance

Corporate flexibility in complying with EPA regs is disappearing

WASHINGTON, D.C.——The push by the Environmental Protection Agency to encourage voluntary environmental audits by electric utilities, combined with a recent wave of citizens lawsuits aimed at forcing compliance with environmental laws, are forcing utilities to pay more attention to establishing and meeting technical environmental specificiations.

It is too early to assess the effect on utilities of the Reagan Administration's move to push for more rigorous environmental auditing. But there has been a surge in citizens lawsuits that, even if these do not actually result in demonstrably stricter compliance, can still work to energize certain EPA enforcement actions that may not have been started without the suits.

New audit initiative

"The agency believes . . . that investment in a structured effort to know how well your firm is meeting its environmental responsibilities will pay substantial dividends," EPA's Milton Russell told attendees at the Edison Electric Institute's Power/Environment Conference.

Russell, who is Assistant Administrator for Policy, Planning, and Evaluation, decried industry disinclinations to conduct such audits on the basis that they might reveal environmental problems that could threaten the utility's financial health.

"This head-in-the-sand attitude can mean disaster," he said.

Russell explicitly addressed utility managers who might be tempted to shrug off the importance of his message because it suggests voluntary actions rather than required ones. "When I offer supportive comments about voluntary compliance activities, that does *not* (emphasis supplied) imply a reluctance on the part of the EPA to enforce when enforcement is appropriate. Potential enforcement is a strong motivating factor."

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Disruptions seen arising from nuclear rate shock

AFUDC, as an accounting factor, could be jeopardized

Dan Utroska
Associate Editor

BARRINGTON, IL——The rate shock associated with some of the 40-plus nuclear plants expected to come on-line in the next few years could seriously disrupt numerous local economies and could radically change the way certain crisis-state electric companies report their financial dealings.

These are the conclusions of two recent reports demonstrating that the potential effects of rate shock can be both direct and indirect.

The reports are *The Public Utility Industry: 1984 Survey of Financial Reporting and Accounting Developments* issued by Price Waterhouse, and *Rate Shock: Confronting the Cost of Nuclear Power*, released by the Environmental Action Foundation.

Rate shock is the impact of unconventionally high electric rates stemming from large plant additions into the rate base.

To the extent that the full cost of a large, expensive nuclear plant is passed along to ratepayers in the form of higher rates, it can result in a direct reduction in electricity demand and the corresponding flight of electricity consumers from the region.

To the extent that public utility commissions and electric utilities attempt to mitigate nuclear rate shock,

continued on page 6

Rep. Waxman, Sen. Byrd square off over future acid rain bill

WASHINGTON, D.C.——The push by House Democrats to pass acid rain legislation in the upcoming session of the U.S. Congress may come up against somewhat weakened opposition in the Senate, if remarks by two key legislastors are any indication of future positions.

In especially strong terms, Rep. Henry A. Waxman (D.CA) has charged that a policy of neglect on acid rain can only bring environmental and economic ruin to important segments of U.S. society.

"Ohio utilities have succeeded in avoiding stringent controls and want us to believe there is no cost to their pollution," he said. "Yet, everyone . . . knows that is not true."

Waxman, who was co-sponsor of the only piece of legislation that received serious attention in the 98th Congress, the Sikorski-Waxman bill (H.R. 3400), said that the cost of pollution created by Ohio utilities is being transferred to millions of Americans living east of that state.

Speaking to attendees of the Edison Electric Institute's seventh annual Power/Environment conference here, Waxman, who is chairman of the House Subcommittee on Health and the Environment, said, "Protecting the profits of utilities in one state by transferring their costs of doing business to other states is bad economics, bad policy, and just plain unfair. And it will not continue. Congress will not stand by and let our economy and environment be held hostage to the unreasonable wishes of some coal or utility companies."

Senator Robert Byrd (D., W.VA), the powerful Senate minority leader from a southern coal-producing state, has been successful in the past in snuffing out legislation coming from the House side. But Byrd told the same conference that he may not always be able to quash such efforts.

Declaring that there were others in the Senate who shared his view that the economic implications of proposed legislation have to be carefully evaluated, and that further scientific research was necessary before moving ahead with such legislation, Byrd said, "A few fingers in the dike will not be able to hold off the flood forever."

A new pragmatism?

Byrd said the acid rain debate may be entering a new phase in which the approach to dealing with the problem would be "more pragmatic."

"Proposals that make no provision at all for the tremendous economic dislocations they would cause are now viewed as far less desirable by many members of Congress," he said.

But he noted, "It is too early to know whether a new, more pragmatic approach to acid rain will emerge in the 99th Congress."

"In light of the incomplete and insufficient scientific data available at present, an acid rain plan that requires an expensive, intrusive, new regulatory program is not in the best interests of the United States," Byrd concluded.

Waxman repudiates the notion that current scienfitic data on acid rain is insufficient to support legislation. "Opponents of acid rain controls ignore the thoroughness of acid rain research and seem to hold an ideology that equates environmental protection with bad economics," he said. "But inaction is causing human suffering and costing our economy billions of dollars in economic damage."

While Byrd maintains that a 10-million-ton control plan would cause ratepayers to face dramatic rate increases, Waxman cites an estimate by the Congressional Office of Technology Assessment that calculates control costs of about $3 billion annually.

"But this figure must be evaluated

continued on page 37

Foreign Power Briefs

Finalizing their $1.5 million agreement with a handshake, Southern Electric International President Harold C. McKenzie, Jr. (l.) and Ayhan Erkan, general manager of the Turkish Electric Authority (TEK), conclude the formalities of signing a new contract in which SEI will provide TEK with accounting and management information system consulting services.

- **The Turkish Electric Authority (TEK)** has hired Southern Electric International, Inc., the consulting company of the Southern Company, to analyze its accounting and management information systems. The consulting company also will implement technical improvements to strengthen TEK's financial reporting and operating functions. The World Bank provided the funding for the three-year, $1.3 million project. SEI President Harold C. McKenzie, Jr. said his firm will provide a base project team comprised of accounting and data processing experts who will work in cooperation with MAGE A.S., a diversified consulting firm based in Ankara.

- **Singapore** recently placed an order with Kraftwerk Union AG (KWU) for a turnkey gas turbine power plant. KWU said the two Jurong power station units will each have a maximum capcity of 130 MW. The first unit is scheduled to go into operation in June 1986.

- **The People's Republic of China** and the M.W. Kellogg Company have signed preliminary agreements that should result in a joint venture engineering company to be based in China and engaged in the engineering and construction of projects in China and elsewhere. M.W. Kellogg said it signed preliminary documents with Sino-Pec International in Bejing in September. Robert W. Page, chairman and chief executive officer of Kellogg Rust Inc., which owns M.W. Kellogg, said "We hope to form the strongest joint venture engineering company in China before the end of the year or early next."

- **Brazil's** Centrais Eletricas do Norto do Brasil S.A. obtained a $170 million medium-term loan from a group of 11 international banks, according to Manufacturers Hanover Trust. Eletronorte, the government-owned electric utility, will use the money for the Tucurui hydroelectric project in northern Brazil. The loan is for nine years and is priced at 1¾ points above U.S. prime at the lender's option.

- **The United Kingdom** and the United States have signed a memorandum of understanding for collaboration in energy research and development. The U.S. Dept. of Energy said the goals of the arrangement are to accelerate energy R&D and to increase R&D efficiency through joint planning. DOE said collaboration is initially planned for fossil fuels renewable energy sources and efficient energy use. DOE Secretary Don Hodel said, "Our two countries have a long history of successful cooperation in energy R&D, which provides a solid foundation for additional collaborative efforts going beyond historical cooperation. Collaboration as envisioned in this new arrangement could lead to greater efficiency through joint planning and a sharing of tasks, facilities, scientific and technical information, costs and human resources."

- **The Italian state electric utility**, Ente Nazionale Energia Elletrica (ENEL), has asked U.S. coal exporters to lower their prices, reports the *Journal of Commerce*. ENEL said it would buy American coal only if U.S. exporters brought down their prices to a level competitive with other exporting countries. ENEL says U.S. coal is approximately $5 per ton higher than its major competitors. In 1984 ENEL said it will import 8.35 million metric tons of coal, including 2 million from America. The Italian utility estimates that demand could jump to 16 million tons oil equivalent next year. ENEL claims it is the single largest importer of U.S. coal

- **Ontario Hydro** sold 739.8 million kilowatt-hours of electricity to the U.S. in September.

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Coal-generated electricity cheaper than nuclear: DOE

WASHINGTON—Electricity is being produced at lower cost in large coal-fired power plants than in nuclear plants, according to the latest survey reported by the U.S. Department of Energy.

The DOE results are in line with the most recent survey results reported by the Atomic Industrial Forum which also showed nuclear costs catching up to coal (see *EL&P*, November, 1984, page 11).

DOE said the generating cost for nuclear plants operating in 1983 was 33.46 mills per kWh compared to 31.83 mills for the coal plants. Generating cost includes actual reported fuel and O&M costs plus an estimated capital component based on a fixed charge rate of 18 percent.

The AIF survey pegged both types of costs for 1983 at 35 mills.

Nuclear costs rising faster

The cost studies are significant because they both show the cost of nuclear-produced electricity rising faster than that of coal. Nuclear electricity cost now equals or exceeds that of coal for the first time in the history of nuclear power in the U.S.

Over the last 3 years

Over the last three years nuclear costs in the DOE report have climbed from 26.15 mills per kWh in 1981 to 32.04 mills in 1982 and 33.46 mills in 1983. The DOE trend for coal has been a slower climb from 28.76 mills per kWh in 1981 (the last year coal costs exceeded those of nuclear in the DOE study) to 31.77 mills in 1982 and 31.83 mills in 1983.

In the AIF survey the nuclear cost rose from 23 mills in 1980 to 27 mills in 1981, 31 mills in 1982, and 35 mills in 1983. As with the DOE survey, the AIF survey showed coal-produced electricity costs rising at a slower rate, from 25 mills in 1980, to 32 mills in 1981, and to 35 mills in both 1982 and 1983.

O&M costs the culprit

The major factor in the shifting positions of coal and nuclear is the relative change in O&M costs, which are rising much more rapidly for the nuclear plants than for coal. In fact, coal plant O&M costs are the same as they were three years ago while nuclear O&M costs have climbed nearly 3 mills per kWh.

The DOE fee of 1 mill per kWh for nuclear waste disposal is included as part of the nuclear fuel cost, which has also been rising more rapidly than coal costs in the past few years. Capital costs, usually assumed to be the culprit in rising nuclear energy costs, have climbed at about the same rate for both generating types, according to the DOE survey.

Survey covers

The DOE survey covers all 55 operating nuclear plants larger than 400 MW and 105 base-loaded coal-fired plants larger than 400 MW. DOE says the nuclear units covered in the survey accounted for 78 percent of all nuclear generation and the coal units surveyed accounted for 29 percent of all coal-fired generation.

United Engineers and Contractors Inc. conducted the survey. Results were reported in the April-June 1984 issue of the DOE publication "Update: Nulcear Power Program Information and Data."

Manitoba pitches hydro power sales to midwest U.S. utilities

CHICAGO—The Canadian Province of Manitoba, located to the north of Minnesota and North Dakota, wants to "prebuild" potential hydroelectric generating capacity and sell the power on a firm basis to U.S. utilities.

Marc Eliesen, deputy minister of energy and mines for the Province of Manitoba gave a high-powered sales pitch aimed at midwestern U.S. utilities at the recent Illinois Energy Conference here sponsored by the University of Illinois.

"It makes economic sense for American utilities to consider importing Canadian electricity," said the Canadian government official. He claimed that in a recent deal signed with Northern States Power for 500 MW over 12 years the American utility's customers will pay 80 percent of what they would have paid for electricity from a new coal-fired plant built by NSP.

Manitoba Hydro makes money off the deal because it can produce electricity much more cheaply than U.S. utilities can, said Eliesen. He said Manitoba electricity customers currently pay half what NSP's customers do. He said Manitoba has the lowest electric rates in North America.

Manitoba currently has 4000 MW of hydro capacity operating chiefly in the Nelson River and Churchill River watersheds in the northern part of the province. A 560-mile, 450-kV transmission link was recently built to beef up ties between the hydro region in the north and the load centers in the south. The province has better ties to the south than it does east or west, said the official.

There is "vast potential" for further hydro development in Manitoba, Eliesen reported. He said there is at least 9000 MW more capacity to be developed.

The capacity now operating can handle Manitoba's internal needs well into the 21st century, said Eliesen, adding, "We are prepared to prebuild our system for export purposes."

"Let me assure you," says Manitoba government official Marc Eliesen, "Canadians are not blue-eyed sheiks."

Good track record

Manitoba has a proven export track record, said the official, based on 20 years of interruptible sales to midwestern U.S. utilities. The province's electricity exports have grown from 1.4 billion kWh in 1975 to 6.5 billion in 1983, accounting for one-third of Canadian exports to the U.S.

U.S. utilities need not be concerned about the reliability of supply from Manitoba, said Eliesen, adding, "Let me assure you Canadians are not blue-eyed sheiks."

Building on its experience with interruptible sales to U.S. utilities Manitoba is now moving into the area of long-term, firm sale agreements. So far an additional 10 billion kWh a year have been negotiated or are in the planning stage.

The first firm deal was signed last June with NSP. It calls for 500 MW for 12 years. Manitoba expects revenue from this agreement to total $3.2 billion.

Eliesen said discussions are currently underway with the Western Area Power Administration, a federal agency that serves midwestern public power companies, for 1200 MW over 35 years. If that deal goes through Manitoba will build a new, $3 billion hydro project.

The official said that discussions are also underway with two different groups of U.S. utility companies: a nine-utility group in North Dakota, Iowa, Minnesota, and Wisconsin; and an eight-utility group in Wisconsin, Minnesota, and North Dakota. Both discussions cover deals in the range of 1100 MW over 35 years.

There are in place a 230-kV transmission link to North Dakota and 230-kV and 500-kV ties to Minnesota. Manitoba is prepared to build new lines, said Eliesen. He recalled problems with T-line construction in a proposed 700-MW seasonal transfer deal between Manitoba and Nebraska. South Dakota denied permission to build the necessary line, setting back the project. Canada, Eliesen assured his U.S. audience, will not impose any regulatory delays on such deals.

"Despite impediments," said the official, "U.S. power sales will grow because they make good business sense."

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Total utility financing drops in 3rd quarter

NEW YORK—Total utility financing in the first nine months of 1984 was $7.1 billion, 47 percent lower than the $13.3 billion issued in the same period in 1983.

A report prepared by Ebasco Business Consulting Company electric utility financing dropped 29 percent to $6.5 billion from last year's nine-month total of $9.1 billion.

Long-term debt issued by electric utilities was $5.2 billion, down slightly from 1983's $5.5 billion. Ebasco said total long-term debt issued by all utilities decreased from $8.1 billion in 1983 to $5.6 billion in 1983.

Preferred financing

Preferred stock financing by electric utilities in the first nine months dropped to $688 million from $1.5 billion during the same period in 1983. Offerings of preferred stock by all utilities decreased 54 percent to $788 million from $1.7 billion.

Common stock

Common stock financing for electric utilities was approximately $610 million, a plummet of almost 71 percent from 1983's $2.1 billion. Common stock offerings for all utilities dropped from $3.5 billion to only $638 million in the first nine months of 1984.

OFFERINGS OF SECURITIES BY INVESTOR OWNED PUBLIC UTILITY COMPANIES
($000)

	January 1 to September 30, 1984		January 1 to September 30, 1983	
	Total	Electric	Total	Electric
[illegible]				
Offered Publicly	[illegible]	[illegible]	[illegible]	[illegible]
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EPRI produces book for HPOF cable designers

PALO ALTO, CA—Utilities can save considerable operating and capital costs by following the recommendations in EPRI's new forced-cooled transmission cable system handbook, said the institute.

EPRI said the handbook provides complete information for designing an optimized forced-cooled high-pressure oil-filled pipe-type cable system. The book presents a step-by-step procedure that a cable system designer familiar with cable ratings can use.

The EPRI handbook includes a discussion of the fundamentals of forced cooling, procedures for calculating and estimating design parameters, and guidelines for system engineering and equipment applications.

For more information on EPRI report *EL-3624*, contact the institute at (415) 965-4081.

Byron approved

WASHINGTON, D.C.—A Nuclear Regulatory Commission Atomic Safety and Licensing Board said in October that Commonwealth Edison should be allowed to operate the two unit 1,120 MW Byron nuclear plant.

The decision reversed the board's denial of an operating license last January because of quality assurance questions.

ASLB said

The ASLB said, "In today's supplemental initial decision we conclude that, with respect to those quality assurance issues within our jurisdiction, there is no impediment to an operating license."

Satisfied

When the Byron operating license was denied in January, Commonwealth Edison was in the midst of a $10 million reinspection program. After evaluating the reinspection program, the ASLB said it was satisfied with the plant's quality assurance program.

Commonwealth Edison had hoped to receive an operating license last February. A utility spokesperson told *EL&P* that the delay has added $100 million to the cost of the Byron plant.

Commercial operation

The spokesperson said Commonwealth Edison hopes to have the first unit in commercial operation in February 1985.

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Electricity bills surveyed by NARUC

WASHINGTON, D.C.—Consumers in the Northeast and New England have the highest electricity bills in the U.S., while those in the Northwest and Rocky Mountain regions of the country have the lowest, according to a recent survey.

The National Association of Regulatory Utility Commissioners (NARUC) said its sixth winter residential electric bill survey found that the nationwide cost of electricity is 7.67 cents per kilowatthour.

Customers in New York City, the most expensive service area, pay more than 15 cents per kWh. The least expensive area is Lewiston, ID, where customers pay approximately two cents per-kWh. See accompanying tables for the ten most expensive and least expensive service areas.

The NARUC report contains winter 1983-84 residential bill comparisons for the largest service territories of the major investor-owned electric utilities. NARUC looked at residential bills between December and February at three levels of energy consumption—250-kWh, 500-kWh and 750-kWh.

Compared to last years' survey, NARUC found that residential electricity bills jumped about 4.4 percent. This contrasts with an approximate 4.1 percent rise in the Consumer Price Index during the same period, said NARUC.

The study shows that in 26 service areas, consumers are paying in excess of 10 cents per-kWh while in 15 other service territories, they pay less than five cents per-kWh.

Other areas of the country where electric bills are high, include Nantucket, MA, (14.48 cents); and Hilo, HI, (13.18 cents). Low bills can be found in Rexburg, ID, (2.98 cents); Spokane, WA, (3.13 cents); and Kalispell, MT, (3.28 cents).

10 MOST EXPENSIVE BILLS

Company	City	State	Total bill*	Avg. cost cents/kWh	Nation rank
Consolidated Edison Co. of New York	New York City	New York	228.26	15.22	1
Nantucket Electric Company	Nantucket	Massachusetts	217.17	14.48	2
Hawaii Electric Light Co.	Hilo	Hawaii	197.75	13.18	3
Maui Electric Co.	Wailuku	Hawaii	197.50	13.17	4
Orange & Rockland Utilities, Inc.	Middletown	New York	194.21	12.95	5
San Diego Gas & Electric Co.	San Diego	California	183.80	12.25	6
Long Island Lighting Co.	Long Beach	New York	181.89	12.13	7
Central Hudson Gas & Electric Corp.	Poughkeepsie	New York	174.52	11.63	8
United Illuminating Company	Bridgeport	Connecticut	174.22	11.61	9
Hawaiian Electric Co.	Honolulu	Hawaii	171.17	11.41	10

10 LEAST EXPENSIVE BILLS

Company	City	State	Total bill*	Avg. cost cents/kWh	Nation rank
Washington Water Power Co.	Lewiston	Idaho	31.14	2.08	190
Utah Power & Light Co.	Rexburg	Idaho	44.73	2.98	189
Washington Watur Power Co.	Spokane	Washington	47.01	3.13	188
Pacific Power & Light Co.	Kalispell	Montana	49.13	3.28	187
Citizens Utilities Company	Kellogg	Idaho	53.43	3.56	186
Pacific Power & Light Co.	Yakima	Washington	56.65	3.77	185
Pacific Power & Light Co.	Portland	Oregon	57.12	3.81	184
Idaho Power Company	Ontario	Oregon	57.78	3.85	183
Idaho Power Company	Boise	Idaho	59.70	3.98	182
Portland General Electric Co.	Portland	Oregon	61.03	4.07	181

*Total bill equals cost of 500 kWh for the three months of December, 1983, January, 1984, and February, 1984.

Source: NARUC

Westinghouse says it will make changes

PITTSBURGH—Westinghouse Electric Corporation said it has reorganized its steam turbine-generator and plant operations division.

Eugene J. Cattabiani, power generation executive vice-president, also announced that Stanley L. Quick, general manager of the steam turbine-generator division, will retire in early 1985.

Westinghouse said Howard Pierce, general manager of the power generation operations division, who currently has responsibility for the unit's manufacturing operations in East Pittsburgh and Lester, PA, and Charlotte and Winston-Salem, NC, has been given the additional responsibility for steam turbine-generator engineering. Pierce also will serve as the site manager at Orlando.

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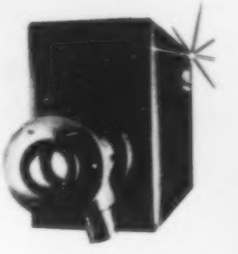

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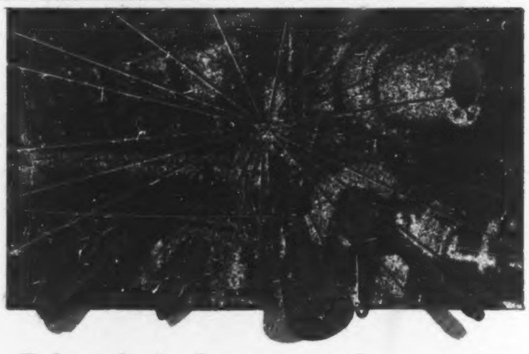

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Volume 63, Number 1
January 1985

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

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Yankee hits new milestone

Yankee nuclear power plant (Rowe, MA), the nation's oldest operating commercial nuclear generating station, hit a milestone last December 12 when it sent out its 25-billionth kWh. In June of this year, Yankee will celebrate another milestone, its silver anniversary connoting 25 years of operation. The plant, which took just 25 months to construct, was completed in June, 1960, at a total cost of $43-million or $245 per kilowatt. For its first 24 years of operation, Yankee has achieved a 74-percent capacity factor.

$750 million reserved for clean coal demo projects

WASHINGTON, D.C.——As a part of the FY 1985 continuing resolution passed by Congress last session, $750 million is being reserved in a special Treasury account for clean coal technology demonstration projects.

The Congressional action is aimed at bridging the gap believed to exist between the Reagan Administration's support for proof-of-principle research and development activities, on the one hand, and the private sector's actual commercialization efforts, on the other.

Concluding that neither the Administration nor the private sector are willing to support intermediate demonstration efforts, Congress also has legislatively directed the Department of Energy to solicit statements of interest from industry, to coordinate the responses, and to issue a report by May 1, 1985.

Details of DOE's solicitation of industry interest is contained in the November 27, 1984 *Federal Register*. The department has set a revised deadline of February 15 for receipt of proposals from industry.

According to one Senate source, the congressional action approving the $750 million expenditure is a spinoff of a bill (S. 1925) introduced by Senator Robert Byrd (D. W.VA.) in October, 1983. Byrd, from a coal-producing state, saw the acid rain debate heating up and became concerned that electric utilities might be forced subtantially to cut sulfur emissions from coal-burning power plants.

Deciding that the only ways to do this were to switch fuels from coal or to install expensive emission control apparatus, Byrd introduced the National Coal Science, Technology, and Engineering Development Act to stimulate and support research into clean coal technology. When the bill failed to reach mark-up, the alternative route of using the continuing resolution (the Congressional alternative to passing all budget bills) was implemented. A joint resolution was passed, directing DOE to take charge of the industry solicitation and funneling the $750 million authorization into a special Treasury account.

Proposal criteria

Clean coal technology demonstration proposals to DOE from the private sector are to identify and describe methods for reducing emissions from new and existing coal-burning power plants and from industrial coal uses. Such technologies should be such that they can be commercialized in the near term.

Proposals should also outline what incentives, including financial assistance, the federal government would have to provide in order to assure

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Rewriting the utility regulation 'legend'

Rapid deregulation of American industry, competitive elements introduced into the electric utility industry by the Public Utility Regulatory Policies Act, and growing belief that the traditional 'utility bargain' with its customers no longer is valid, makes electric industry regulation increasingly tenuous.

Dan Utroska
Associate Editor

LOS ANGELES—It was titled, *Public Service Regulation: The Legend Continues.* But the 96th annual convention of the National Association of Regulatory Utility Commissioners (NARUC) revealed clearly that the legend may, in fact, be diminishing to its more superficial rendering; that of "a popular myth of recent origin" (Webster).

In an era that has witnessed the deregulation of the banking and securities industries; the airlines industry; the telecommunications and trucking industries; and, in part (and possibly soon to be complete), the natural gas industry; the regulated electric utility industry appeared to some industry observers to be little more than a fading anachonism.

As noted utility economist Irwin Stelzer lightly put it, it might be possible to introduce enough competition into the residual energy regulatory structure to enable the 111th NARUC convention, slated for the year 2000, to be held in a telephone booth.

To others, however, regulation of electric utilities constitutes one of the last vestiges underlying civilized cultures.

The Public Utility Regulatory Policies Act of 1978 (PURPA) already has cut deeply into the idea that electricity generation is inherently a regulated enterprise. Providing encouragement for the development of cogenerators and small power producers who are exempt from traditional utility regulation, PURPA-drafters envisioned a host of electricity generators who are enabled to locate, build, and sell their energy according to the principles of a market economy.

Deregulation is messy, chaotic

"To the regulator . . . competition is a damned nuisance—entirely apart from the vulgar consideration that deregulation also threatens his own source of livelihood," celebrated economist and deregulation guru Alfred Kahn told the NARUC assembly. Kahn was head of the Civil Aeronautics Board when the airlines industry was deregulated.

Regulators see deregulation as such a nuisance, Kahn maintains, because it is so unpredictable and messy: under competition businesses move in and out of markets, they change their product and service offerings at will, they alter their production schedules and prices.

By contrast, the regulator is seen to prefer continuity of service and stability of prices and service offerings. "Freedom of exit is the last thing he wants," Kahn declared. "The regulator doesn't trust the market and free entry to satisfy economically legitimate demands."

Yet, Kahn's enthusiasm for deregulation, so broad that it encompasses numerous major industries, dwindles noticably as it encounters the electric utility industry.

Deregulation is feasible, Kahn says, only where competition can be stimulated in its place.

"It's a very different story in the electric utility industry," Kahn told *EL&P* in a telephone interview. "Electric utilities don't fit the mold yet."

Referring to his analyses, which he admits are very preliminary, Kahn said, "I can't figure out how to get sufficient competition to protect the public."

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Marginal cost pricing urged as premise for logical energy policy

LOS ANGELES——The use of marginal cost pricing, in both excess and boundary energy-sufficiency situations, could work to transform the current improvisational energy situation into a rational, cohesive market policy, a noted industry economist has declared.

Charging that electricity pricing historically has been little more than "*Ad hoc-ery* run wild," Irwin Stelzer told the National Association of Regulatory Utility Commissioners (NARUC) that "our goal is to make sufficient supplies of energy, in whatever form is demanded, available to all who are ready, willing and able to pay prices equal to the marginal cost of producing that energy."

Stelzer is president of the National Economic Research Associates, Inc.

'Informing principle'

Implementation of marginal cost pricing as the "informing principle" of energy policy could, Stelzer said, effectively meet challenges in such wide-ranging areas as acid rain and nuclear waste disposal; securing na-

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Foreign Power Briefs

- **China** said it will set up its first nuclear safety agency, reports *United Press International*. Wu Xing, head of China's science commission said the Bureau of Nuclear Safety will draw up safety standards and regulations for the construction of nuclear plants, issue manufacturing and operating licenses and become involved in safety research with other countries.

- **Canada's National Energy Board** (NEB) reports that nuclear power will supply 22 percent of the nation's electrical production in the year 2005. The group recently released a new report, *Canadian Energy Supply and Demand 1983-2005*.
The report projects that the use of energy by Canadian consumers is expected to grow at a rate of 1.6 percent a year. NEB said it assumes an annual GNP growth rate of 3.4 percent to 1990 and 3 percent a year from then to 2005. The report found that excess electrical capacity will exist in Quebec and Ontario, supporting imports to the U.S. NEB said that Canada's total electrical generating capacity will have to grow from 84 GW in 1983 to 150 GW in 2005 to meet the expected demand.

- **The Ivory Coast's National Electricity Company** (E.E.C.I.) has awarded NCR Corporation a $2 million contract to provide specialized equipment for decentralizing the nation's electricity payment, collections and record-keeping systems. NCR said installation of the new system begins immediately and continues through 1987. Total electrical output for the nation was two million megawatt hours in 1982.

- **Indonesia's** national power authority, Perusahaan Umum Listrik Negara (PLN) signed a $186 million contract with Babcock & Wilcox for the supply and installation of two complete 400 MW steam generation plants for the Suralaya Steam Power Plant on Java. Also involved in the contract are B&W Canada, P.T. B&W Indonesia and Marubeni Corporation. B&W Canada will have technical and commercial responsibility for the contract. Marubeni and B&W Canada are supplying the 400 MW Suralaya units 1 and 2. B&W said they will begin operation in 1984 and 1985, while units 3 and 4 are scheduled for operation in 1988 and 1989.

- **Taiwan Power Company's** Maanshan Unit 1 nuclear plant has gone into commercial operation, reports Westinghouse. The three loop, 900 MW pressurized water reactor is the first PWR to go into operation in Taiwan. The plant was completed in 74 months. Westinghouse said Taiwan Power Company is planning to order two more nuclear power plants in 1985.

- **Chichibu Cement Co. Ltd. of Japan** and Pacific Nuclear Systems have signed an agreement to bring patented Japanese nuclear waste containment technology to the United States. Pacific Nuclear will distribute Chichibu's polymer impregnated cement technology. David F. Jones, Pacific Nuclear president, said the move will provide U.S. utilities "an additional cost-effective and environmentally superior option for the storage and disposal of low-level radioactive wastes."

- **The Southwest Electric Power Administration of the People's Republic of China** and Detroit Edison's Utility Technical Services, Inc. have signed a preliminary agreement whereby UTS will provide advice on how to increase the steam generating capacity of the coal-fired Huayingshan power plant.

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Ruckelshaus resigns; Thomas named EPA head

William Ruckelshaus

Lee M. Thomas

WASHINGTON, D.C.—After serving only 18 months as administrator of the Environmental Protection Agency, William Ruckelshaus announced his resignation in late November.

President Ronald Reagan quickly nominated Lee M. Thomas, the 40-year-old EPA assistant administrator for solid waste and emergency response, to replace Ruckelshaus.

The resignation of Ruckelshaus came as a surprise to much of Washington, but the former EPA head said he felt it was time to move on.

Ruckelshaus, who was the first EPA administrator under President Richard Nixon, came back to the EPA after numerous scandals had rocked the morale and operation of the agency.

Thomas received the endorsements of Ruckelshaus and the environmental community.

Friends of the Earth spokesperson Liz Raisbeck said, "We're pleased. Thomas is a good, solid professional."

Raisbeck said Thomas's first priority should be to save the EPA budget from being cut and to increase it, if possible.

She said the environmental community is concerned that Thomas may not have as much political clout as Ruckelshaus in protecting the agency's budget.

Ruckelshaus brought Thomas to the EPA in 1983 to head the Superfund, after Rita Lavelle left under charges of perjury.

Previous to coming to EPA, Thomas worked at the Federal Energy Management Agency. He also worked for the Office of the Governor of South Carolina.

Thomas has a Master in Education degree from the University of South Carolina and a Bachelor of Arts degree from the University of the South. He and his wife have two sons.

DOE forms Coal Council

WASHINGTON, D.C.—Secretary of Energy Don Hodel said he has established a National Coal Council to provide recommendations to the Executive Branch on government-industry cooperation in coal-related matters.

The Council will be made up of between 100 and 125 members from utilities, coal companies, state and local governments, environmental, labor, user, research, academic and tribal government organizations.

DOE said the Coal Council will be patterned after the National Petroleum Council which was formed in 1946.

Said Hodel, "The Reagan Administration believes the time has come to give coal—our most abundant fossil fuel resource—the same voice within the federal government that has existed for petroleum for nearly four decades. I expect the National Coal Council to attain the same status and credibility within the coal industry that the NPC has achieved within the oil and gas community."

The Council will be responsible for assisting government and industry in determining ways to improve cooperation in areas of coal research, production, transportation, marketing and use.

NCA believes

National Coal Association President Carl E. Bagge said he believes an active coal council will help the government deal more effectively with the variety of issues directly or indirectly affecting the production and use of coal.

"Many matters relating to coal are considered by separate government agencies, some of which don't talk with one another," said Bagge. "The Council will provide a mechanism for better focusing the government's attention and bringing industry-wide expertise to bear on the most important issues."

Secretary Hodel said the initial Coal Council appointments indicate that "the Department intends to have a diverse spectrum of the highest caliber of individuals who are committed to improving the role coal can play in both our nation's and the world's energy future."

Among the electric utility representatives are: Joan Bok, chairperson of New England Electric System; James O'Connor, chairman and president of Commonwealth Edison Company; and W.S. White, Jr., chairman of American Electric Power Co.

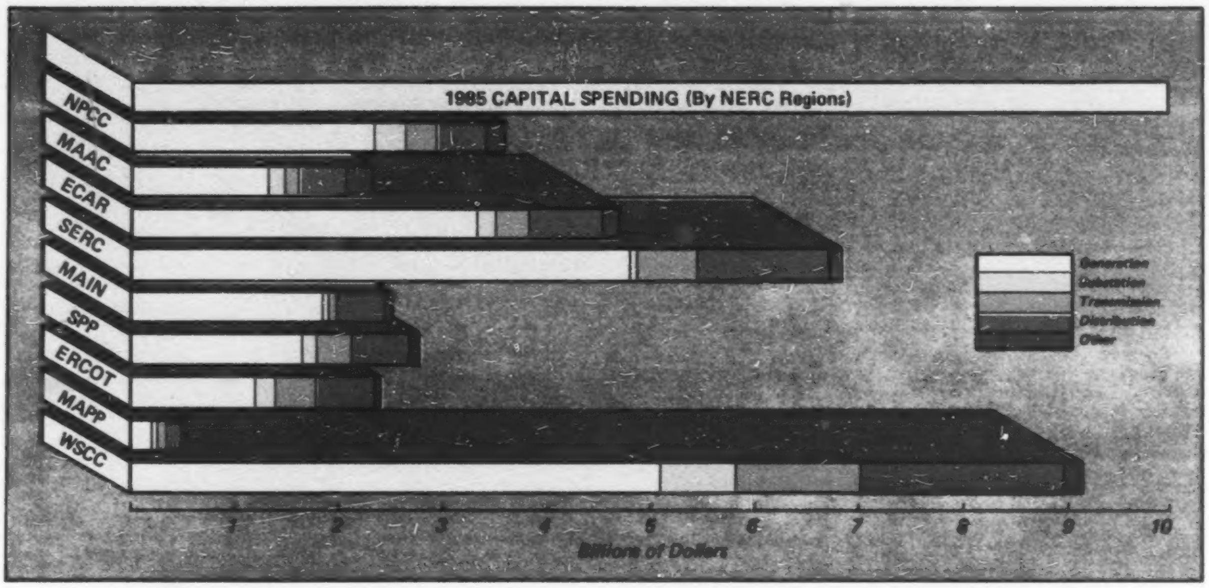
DOE said the Council's initial agenda will include such topics as the impact of federal policies on coal production, marketing, and use; the appropriate size of federal coal research and development; and coal transportation issues.

Nuclear meeting set

LYNCHBURG, VA—Topics such as fuel management, ALARA, robotics, and steam generator health care will be covered at Babcock and Wilcox's tenth nuclear operating and maintenance experience conference.

Dates announced

The company announced the meeting will be held April 17-19.



'85 capital spending to fall, financing and regulatory needs changing

Robert A. Lincicome, Editor-in-Chief
Robert W. Smock, Managing Editor
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Electric utilities will slash construction spending in 1985 and in each of the following four years as they adjust to stable demand growth and current excess generating capacity. This turnaround from the expansionary days of the last two decades, which will intensify the problems of equipment manufacturers and suppliers to the industry, will result in reduced need for external financing. Concurrently, regulators will be confronted increasingly with new questions and criteria as they seek to equate their responsibilities to power suppliers and consumers.

These are the overall conclusions resulting from *EL&P's* most recent survey of the industry, completed in late-November. Here are some of the other conclusions:

☐ Utilities will spend some $34.6-billion for new plant and facilities in 1985, reflecting a drop of nearly 10 percent from 1984 and down some 13½ percent from 1983.

☐ Construction spending will continue to decline through 1989 with the completion of the ambitious expansion plans launched in the early-and mid-1970s.

☐ As capital requirements decline, the need for new financings in the market will decline steadily until the end of the decade when most utilities will be able to generate necessary capital internally.

☐ Rates, which have climbed rapidly and steadily through the last 10 years, will stabilize and even decline in some areas over the next several years. With the exception of rates for utilities bogged down with huge nuclear plant completion costs, most rates should grow at less than the general rate of inflation.

☐ New and innovative rate structures will be more commonplace, with emphasis on providing incentives to customers to control their energy use in order that electric utilities may operate in an optimum economic manner and postpone new construction.

☐ The regulatory environment can be expected to change as new energy technologies develop and economics are altered. Other factors contributing to a changed regulatory climate are increased competition between energy sources, deregulation and greater non-regulated, diversified utility activities and recognition by regulators of the need for innovative, flexible regulation.

☐ No dramatic changes in technology will occur in 1985, but progress in several areas is expected. Chief among these are the use of coal-water mixtures as substitutes for oil in oil-fired plants, decontamination of a an operating reactor's entire primary system, HVDC transmission, distribution automation and the use of fiber optics for data transfer and control. Longer-term gains are expected in fluid-bed combustion, coal gasification, photovoltaics, plant life extension and facilities upgrading.

Late information

Electric Light & Power's investigation was launched in early October. The effort included staff contacts and interviews with industry officials, current and former regulators, financial analysts, utility managers and engineers. Industry construction expenditures were obtained by survey of some 200 electric utilities, municipal electric organizations, cooperatives and federal agencies, with the results projected to the entire industry. Last information was received the end of November.

1985 capital spending declines

According to *EL&P's* survey, electric utility organizations will spend $34.6 billion for new plant and facilities in 1985. This represents a decrease of almost 10 percent from estimated 1984 spending of $37.9 billion.

Total 1985 spending also reflects the continuing shift in spending away from heavy generation investment as the ambitious capacity-expansion programs launched in the mid 1970s come to an end. Spending for power generation, estimated to be $21.2 billion in 1985, will be about 61 percent of total capital investment. A year ago generation spending was estimated to be about 65 percent of construction spending after running above 70 percent for the previous 10 years

Generation system investment has been adjusted to allow for continued slippage in construction schedules.

At the same time, spending for substations and for transmission and distribution lines has increased proportionately, to 34.7 percent of total spending. This increase reflects greater investment by utilities to restore T&D systems to their former condition after letting system construction and maintenance slide during the years of heavy generation spending. It also is the result of recognized need to strengthen interconnections with neighboring utilities for reliability and for economy power purchases as a substitute for expensive oil-fired generation. The improvement in the growth of the housing market also is a major factor.

Investment for new substations is projected to be $2.2 billion in 1985. This is an understatement of actual spending, however, since some utilities reported substation investment as part of transmission and distribution construction plans. This also means that T&D spending is somewhat overstated.

Investment for new transmission

Continued on next page

NORTH AMERICAN ELECTRIC RELIABILITY COUNCILS

ECAR	East Central Area Reliability Coordination Area
ERCOT	Electric Reliability Council of Texas
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interpool Network
MAPP	Mid-Continent Area Power Pool
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council

1985 CAPITAL SPENDING BY NERC REGION (CONTIGUOUS U.S. ONLY)
(in $1000's)

Region	Generation	Substations	Transmission	Distribution	Other	Total
NPCC	$ 2,461,501	$ 194,569	$ 193,027	$ 606,504	$ 100,268	$ 3,555,869
MAAC	1,265,044	155,456	105,904	476,516	272,159	2,275,079
ECAR	3,280,229	146,658	388,813	691,080	119,856	4,626,636
SERC	4,742,060	30,509	538,429	1,317,922	189,338	6,818,258
MAIN	1,876,800	49,663	77,681	445,916	71,081	2,521,141
SPP	1,677,839	138,919	355,837	568,702	79,498	2,820,795
ERCOT	1,203,714	194,380	362,934	595,323	68,334	2,424,685
MAPP	200,919	45,847	87,720	152,941	14,135	501,562
WSCC	5,046,705	605,268	1,248,464	1,936,133	256,261	9,092,831
Total	$21,754,811	$1,561,269	$3,358,809	$6,791,037	$1,170,930	$34,636,856
	%	%	%	%	%	%
NPCC	69	5	5	18	3	100
MAAC	56	7	5	21	11	100
ECAR	71	3	8	15	3	100
SERC	70	1	8	19	2	100
MAIN	74	2	3	18	3	100
SPP	59	5	13	20	3	100
ERCOT	50	8	15	25	2	100
MAPP	40	9	17	30	4	100
WSCC	56	7	14	21	2	100

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lines and facilities is projected to be $3.2 billion, reflecting a slight decline in dollars from 1984, but an increase in the proportion of total funds to be expended.

Distribution spending, projected at $6.6 billion, represents an increase both in total dollars and percentage of total investment for 1985.

Spending will be greatest in the western states and in the sunbelt states of the southeast

5-year capital spending outlook

For the 5-year period running through 1989, overall capital spending is projected to decline steadily (see table). From $34.6 billion in 1985, capital spending will decrease steadily through the period, with 1989 spending estimated to be $21.3 billion, a decrease of 38.6 percent.

Generation spending will continue to be the largest functional area of spending, representing 53 percent of total capital spending over the 5-year period. But annual spending for generation will drop steadily until in 1989 it is expected to be less than $9 billion, representing 41.9 percent of total capital spending that year, the lowest percentage since the 1960s.

The major factors in the reduction of generation investment are, as generally recognized, completion of the ambitious construction programs launched in the mid-1970s, slower-than-expected load and demand growth, resultant large generating reserves and marked reductions in future demand-growth projections.

Also a factor is the potential for substantial amounts of cogeneration capacity to come on-line as the decade comes to a close.

Spending for substations, transmission and distribution facilities over the 5-year period will total $8.6 billion, $16.5 billion and $34.3 billion respectively. This means that 5-year spending for substations will be 6.0 percent of total spending, transmission will represent 11.9 percent and distribution 24.7 percent.

Because of the shift away from generation spending over the period, spending for substations, transmission and distribution will increase proportionately, even though total dollars decline. By 1989, for example, substation construction will be 5.6 percent of total capital spending. Transmission will be 13.9 percent in 1985, while distribution will be 34.0 percent of capital spending.

The rapidly developing far western and southeastern sections of the country will be the areas where system expansion will be greatest over the 5-year period, followed by the heavily industrialized east north central states and Texas.

Shift in financing needs

In general, most electric utilities are doing quite well in terms of meeting their responsibilities to shareholders. Earnings for most companies are up substantially, again, this year. Rates of return for many companies are nearing or surpassing the limits set by their commissions.

With their ambitious construction programs ending, kilowatthour sales up as the result of greater post-recession industrial activity and slower increases in operating expenses, most utility managements are looking forward to continuing the rebuilding of strong relationships with shareholders. Overall, most utilities should enjoy an excellent financial year in 1985 and beyond.

The image of the utility industry as an industry in trouble is the unfortunate result of bad news getting the headlines. The financial misfortunes of the few companies weighed down by the excess financial requirements imposed by out-of-control nuclear projects—such as Consumers Power, Public Service of New Hampshire and Long Island Lighting—far overshadow the successes of the majority of the industry.

Fortunately, according to Mitchell Diamond, Booz-Allen principal, at the recent *Energy Daily* symposium on utility financing, "The financial markets clearly understands the difference between the majority of companies enjoying strong cash flows today and the few that are still struggling with nuclear projects."

Region	1985	1986	1987	1988	1989	Total
NPCC	$ 3,556	$ 2,647	$ 1,706	$ 1,541	$ 1,079	$ 10,529
MAAC	2,275	1,933	1,849	1,361	1,310	8,728
ECAR	4,627	3,114	3,026	3,275	2,469	16,511
SERC	6,818	7,691	5,391	4,809	3,872	28,581
MAIN	2,521	2,387	2,231	1,236	1,037	9,412
SPP	2,821	2,502	1,935	1,584	1,819	10,661
ERCOT	2,425	3,224	3,433	3,300	2,915	15,297
MAPP	502	680	589	619	835	3,225
WSCC	9,092	7,965	6,591	6,133	5,935	35,716
Total	$34,637	$32,143	$26,751	$23,858	$21,271	$138,660

	1985	1986	1987	1988	1989	5-Year Total
Generation	$21,191	$18,337	$13,732	$11,355	$ 8,913	$ 73,528
Substations	2,221	1,954	1,600	1,699	1,183	8,657
Transmission	3,196	3,630	3,395	3,349	2,951	16,521
Distribution	6,592	6,957	7,021	6,516	7,223	34,309
Other	1,437	1,265	1,003	939	1,001	5,645
Total	$34,637	$32,143	$26,751	$23,858	$21,271	$138,660

With declining construction budgets will come the opportunity for utilities to reduce the need for outside capital. Robert Burke, senior vice president of the energy division of Moody's Investors Services, Inc., says the reduction in construction expenditures will lead to less financing overall for the balance of the decade. Burke sees no pickup in construction or financing until well into the '90s.

Another who sees electric utilities' financing needs decreasing is Neal Kurzner, an analyst with Solomon Bros. Kurzner believes that utilities will finance about 65 percent of their requirements internally in 1985 and perhaps 80 percent in 1986. "I see declining construction and improved earnings for the next few years," he commented.

Pat Madden, an analyst with Duff & Phelps, believes there will be a construction hiatus until the early 1990s. His projections call for utility capital spending budgets to decline until through 1991, then begin to increase again in 1992. Through the end of this decade, he believes the industry "may be able to generate all its new capital on its own." When the need for new outside capital returns, traditional sources of funds will be used, he believes.

While the need for external funds for new construction will be small in the next 5 years, some $8.7 billion in low-interest electric utility securities will mature. These must be retired, which would adversely affect cash flow, or be rolled over, which will push the embedded cost of debt up.

Regulatory environment to change

Utility regulation is in a state of transition across the entire country and from comments of regulators, the outlook over the next few years is for more of the same. Flexibility and innovation are qualities most often mentioned as necessary to carry that transition through to an effective conclusion.

William O. Doub, former state and federal regulator, said that the challenge for innovative regulation is as much a necessity now as it was 10 years ago following the Arab oil embargo. Doub observed that "the delicate balance between the requirements of the utility and the protection of the ratepayers from unfair and unreasonable rates was acheived with amazing success.

"Yet today, state commissions are not frankly facing up to the challenge of the nuclear regulatory problem that exists," he said. "Instead of the innovative application of regulatory techniques to solve these difficult and unprecedented problems, the response of many regulatory bodies has been to simply initiate a process of faultfinding and fault allocation. Where we should be fixing the problem, too many regulators are more interested in fixing the blame."

He suggested that under current tax laws, cancellation of some troubled nuclear plants, may appear to offer certain financial advantages. But, he declared, it is virtually impossible to conclude that these plants will not be needed in a very short number of years, given a growing population and economy.

"The price of an unadequate supply of electricity will be far greater to the consuming public and the national economy ultimately than the cost associated with the completion of [nuclear] units now in the pipeline, even if coupled with a certain amount of excess capacity in the near term," he concluded.

Raymond J. O'Connor, chairman of the Federal Energy Regulatory Commission, also called for greater creativity and innovation in the regulatory process, suggesting that regulators must recognize and understand the trends and rapid changes in the energy arena. Principle developments, he said, include the new level of competition among energy sources and the willingness of industry and other customers to seek independence from utilities. O'Connor pointed to the movement of utilities away from their traditional single service, as they get into energy services, load management, conservation, and alternative generation technologies. Another major factor affecting both supply and regulation is the move to decentralized energy potential.

One aspect of this latter development is that state PUCs "are seeking and finding a more active role in shaping the energy futures of their states," he noted. "Many have aggressively pursued conservation, wheeling, load management and alternate sources of supply in ways that are sensitive to local circumstances.

"The lines are geting blurred. Electric utilities are diversifying into non-regulated businesses and non-regulated businesses are moving into the electricity business as co-generators and small power producers."

He also commented that U.S. utility contracts for Canadian power and Canadian concerns about air pollution have made electricity an international commodity, raising a number of new issues that heretofore were beyond the scope of utility regulators.

State regulator Steven Hamm, administrator of the South Carolina Department of Consumer Affairs, speaks up for alternate methods to resolve regulatory disputes, instead of always relying on the adversarial hearing process. He said that the Edison Electric Institute has shown leadership in this area "by initiating a joint effort with representatives of several prominent consumer groups to explore new uses of negotiation to resolve conflict."

Slow technological development

No dramatic changes are in store for electric utility technology in 1985, but there are evolutionary trends that should show progress this year.

On the generation side, development is aimed at getting coal into plants burning oil or gas and at upgrading operating coal-fired plants.

A leading fuel-conversion technology for the near term is the use of coal-water mixtures as a cost-reducing substitute for oil in units designed to burn oil. Utility use of coal-water mixtures is focused on a demonstration program managed by the Electric Power Research Institute. EPRI has narrowed its choice for the demo site to seven utilities. Final choice may be announced by the end of the year. A primary goal for this year is development of a large-scale, reliable burner to handle the erosive coal water mixtures. Florida Power & Light, one of the finalists in the EPRI demo program, says it may move on its own to burn coal-water fuel in its 400-MW Sanford unit 4 as early as 1986.

Fluid-bed combustion has already moved into the demonstration phase, but it's a more complicated technology than coal-water fuel and will take longer to reach commercial adoption. EPRI estimates it will take at least another 5 years to bring atmospheric-

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Forecast report . . .

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pressure fluid-bed combustion to the industry on a commercial basis.

There are three large utility projects underway. Construction has begun on a 125-MW fluid-bed retrofit to a Northern States Power unit and on a new 100-MW fluid-bed plant at Colorado Ute Utilities. TVA plans to begin construction next year on a 160-MW fluid-bed boiler to be retrofitted to a unit at its Shawnee station.

Several other new coal-burning technologies are in various stages of development. For example, coal gasification is being demonstrated at the 100-MW Coolwater coalgas-burning combined cycle plant that started operating last summer. An 80-MW coalgas demonstration project is in the startup phase at Illinois Power. Other projects, such as the use of finely ground, micronized coal in oil-designed units and the retrofit of high-temperature, slagging combustors to allow burning of coal in such boilers also are underway.

Technology development for operating plants is aimed at retrofitting new hardware to improve efficiency or reliability and to extend the life of plants approaching retirement age. Utilities like Pennsylvania Power & Light and Potomac Electric Power have taken the lead in investigating the possibility of making substantial investments in old plants.

The idea is to spend several hundred dollars per kW, compared to several thousand dollars for a kilowatt of new capacity, to extend the life of plants that would otherwise be retired. PEPCO announced such a program for its Potomac River station. So far, that's the only formal life extension program announced, but many other utilities are conducting studies and 1985 should see announcement of a few more projects.

On a smaller scale, many utilities are investing in more sharply focused upgrading projects for operating plants. Hardware to improve thermal efficiency by reducing excess air required for combustion is an example. Another is replacement of old control systems with new distributed digital systems.

The concept of using modular, megawatt-scale fuel cells in utility systems will get a boost this year as construction begins on a 7.5-MW fuel cell at Southern California Edison.

New nuclear generating technology is aimed almost exclusively at improvements at operating plants. A major effort just beginning is aimed at improving the capacity factors of the 86 operating nuclear reactors.

Another trend taking hold at operating nuclear plants is the routine decontamination of radioactive subsystems to reduce maintenance costs during outages. The first decontamination of a modern operating reactor's entire primary system, including fuel, may take place this year.

Unlike aging fossil plants that are being considered for life-extension programs, aging nuclear plants are being retired and will be decommissioned in growing numbers. In 1985 the Shippingport reactor will be dismantled and removed from its site near Pittsburgh, the first major dismantlement of a commercial reactor.

Utility involvement in exotic, alternative energy sources will continue to be chiefly limited to California, where the combination of state and federal tax incentives overrides the high costs of these energy sources for non-utility investors. This year will see activity in California on wind farms, solar parks, and other exotics move forward at a fever pitch because the federal tax credits will end at the end of the year and extension appears unlikely. About 250 MW of utility-connected windfarm capacity is operating, with another 500 MW to be installed this year to beat the deadline.

Utilities remain relatively uninterested in investing in alternative energy sources because they aren't eligible for many of the tax incentives that make the investments attractive. Photovoltaic solar power, for example, holds promise for bulk power generation because of its simplicity and because advances in technology are bringing down the price. Nevertheless, electricity from a photovoltaic solar plant still costs five to ten times as much as electricity from conventional sources.

New T&D technology is gaining importance as utilities strengthen ties to neighbors, buy increasing amounts of power from distant sources, and seek to improve system reliability.

Comprehensive automation of distribution systems, for example, is being demonstrated this year by Carolina Power & Light, which is testing a variety of devices and systems on three 23-kV feeders.

EPRI is helping to bring modern electronic capabilities to transmission system protection with a demonstration of digital microprocessor-based protective relaying on the Public Service Electric & Gas Co. system.

High-voltage direct current transmission is gaining in popularity as a way to bring relatively lower-cost coal-based electricity to areas dependent on oil-fired capacity or areas facing a shortage of capacity. Suppliers say the market potential is for as much as 20 GW of new HVDC power transfer capacity, in addition to the 12 GW now in operation or under construction.

Another transmission-related technology development of interest is the concept of using composite ground wires with fiber-optic data transmission capability operating over utility rights-of-way. The high data transfer capacity of fiber optic lines opens up the possibility of utilities diversifying into a new business area, selling bulk data transfer services. Utilities such as AEP and South Carolina Electric & Gas are installing prototype systems to see how they work.

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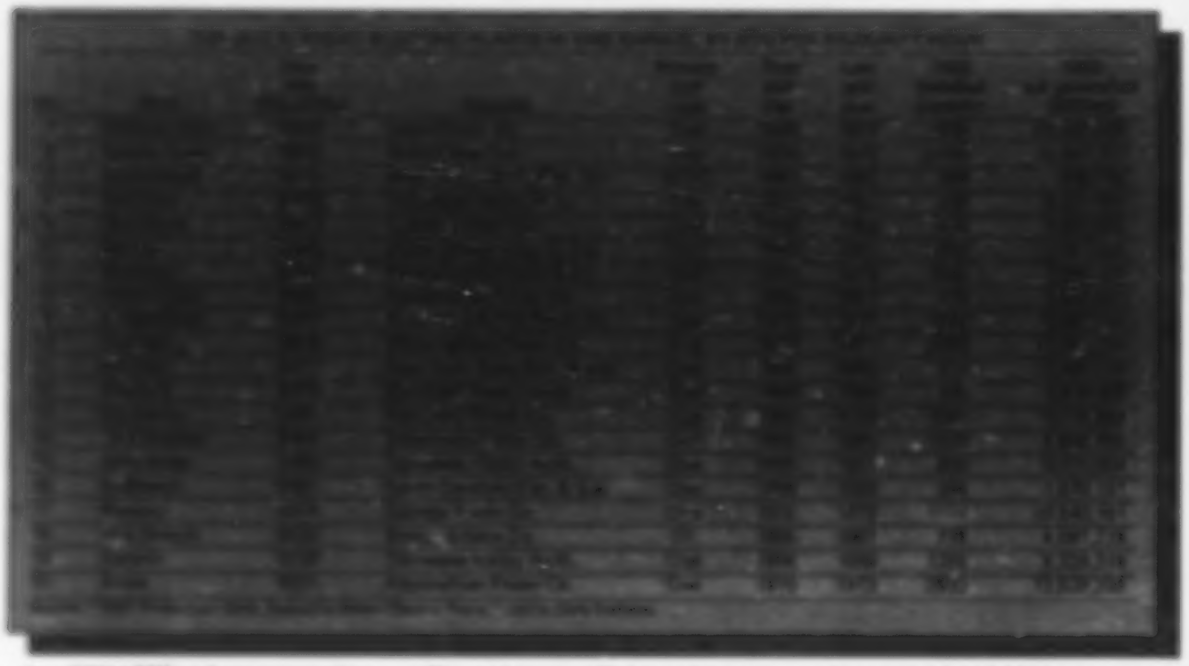
Most efficient, lowest cost plants identified

WASHINGTON—Duke Power operated the most efficient steam-electric generating stations in 1982 and West Texas Utilities and Gulf States Utilities operated the stations with the lowest production costs, according to data in the latest production cost report by Utility Data Institute, Inc.

The report includes 1982 production expenses, fuel expenses, electrical generation, and thermal efficiency on a plant-by-plant basis for 644 large (over 200 MW) steam-electric stations. The group accounted for 95 percent of the total steam-electric generation in 1982. The total includes 333 coal-fired plants, 167 gas-fired, 89 oil-fired, 49 nuclear, three combined-cycle, one petroleum-coke-fired, and one geothermal station.

There are separate tables ranking the top 100 in three different categories: by total generation, by production expenses, and by heat rate. It is important to note that the data cover multi-unit plants, not individual units. The primary fuel for multi-fuel plants is noted but the fuel cost for all fuels is reported.



Of the top 100 plants ranked by output, 69 were primarily coal-fired averaging 9.11 million MWhr of generation in 1982 each, 20 were nuclear plants averaging 8.81 million MWhr, 9 were gas-fired averaging 8.33 million MWhr, and 2 were oil-fired averaging 8.41 million MWhr. The plant with the highest output in country was Detroit Edison's coal-fired Monroe station with a 1982 installed capacity of 3014 MW and net generation of 18.3 million MWhrs.

Of the top 100 plants ranked by production cost, 60 were coal-fired with an average production expense of 15.72 $/net MWhr, 32 were nuclear averaging 12.02 $/net MWhr, and 8 were gas-fired averaging 8.97 $/MWhr. These costs do not include a capital component.

The 100 most efficient plants include 76 coal plants, 12 oil plants, 11 gas, and one combined cycle. The top 20 are shown in the table. Nuclear plants were excluded from the table by UDI because of "variability" in reporting methods.

A fourth table lists data for all 644 plants including fuel expense. Average fuel expense for all the coal-fired plants was 18.33 $/MWhr, average for all the gas-fired plants was 26.27 $/MWhr, average for all the oil plants was 45.06 $/MWhr, and average fuel expense for the nuclear units was 5.95 $/MWhr.

"1982 Production Costs, Operating Steam Electric Plants," is available from UDI at 2011 I St. NW, Washington DC 20006. It costs $150.

Balsam Meadow tunneling continues

After "drilling" the blasted-out crown portion of the 10,000-ft. underground powerhouse, workmen continue to drill and blast another 60 feet downward to form the "breadloaf"-shaped chamber 1,000 ft. below surface for Southern California Edison Company's Balsam Meadow Hydroelectric Power Project in the Sierra Nevada mountains. When completed in late fall 1987, SCE said the $321-million underground hydro facility will add 200 MW of capacity to Edison's Big Creek hydroelectric complex.

NRC study says nuclear power plant experience lessons being forgotten

WASHINGTON—It's not unusual for nuclear power plants to experience a total loss of safety systems—it happened 120 times in the U.S. in the last three years—and there are continuing problems with the ability of utilities to learn from such experiences, according to a recent NRC report.

The study was published by NRC's Office for Analysis and Evaluation of Operational Data and it contains some unfavorable judgments about the learning ability of utilities operating nuclear plants.

For example, the report says "...at times, repetitive events occur which indicate that corrective actions taken at the individual plants are not as long-lasting or as effective as anticipated, and the lessons of experience seem to be sometimes lost or forgotten with time."

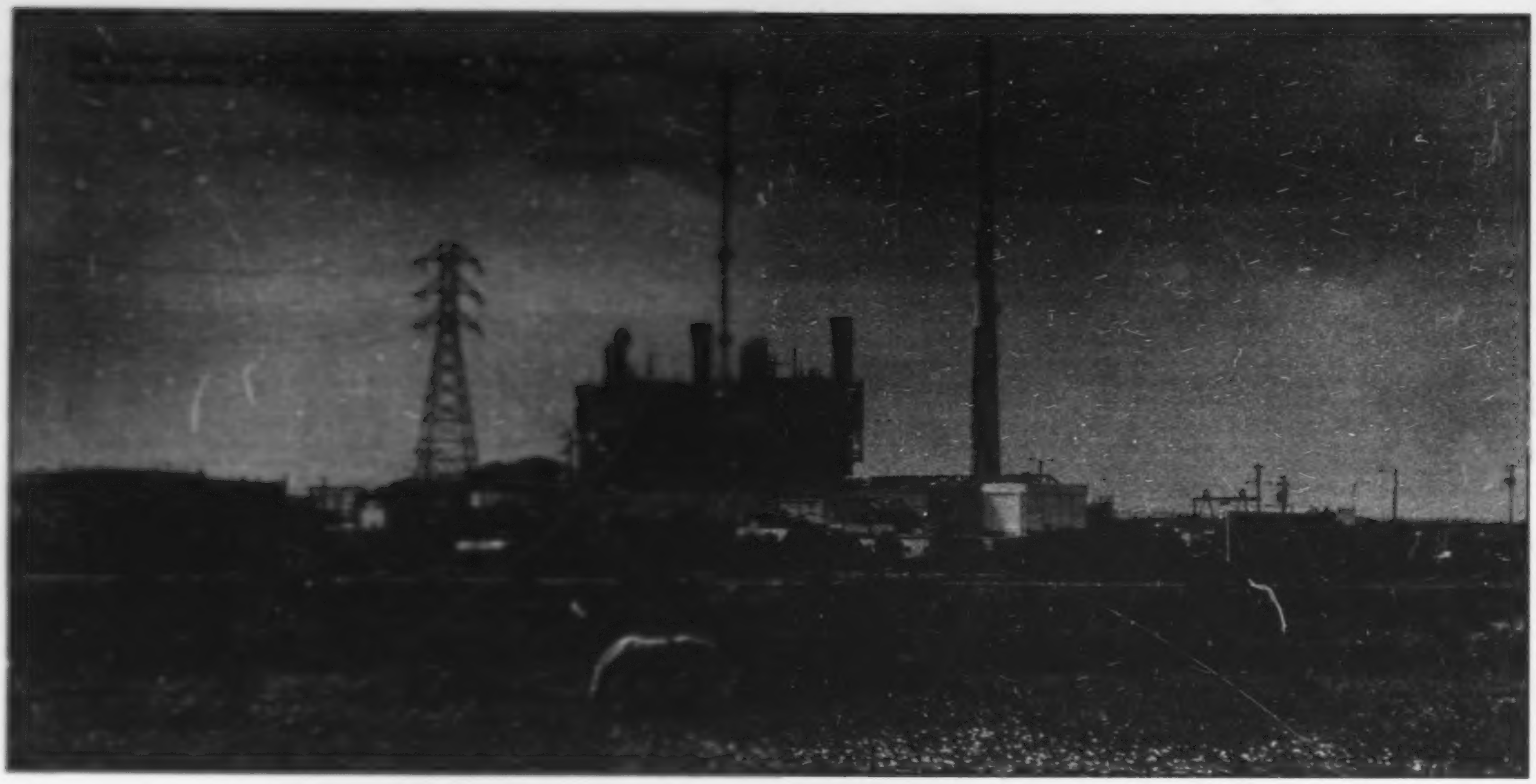
It stresses the importance of learning from experience because serious incidents such as total loss of a safety system are not rare at nuclear plants: "Operating experience continues to indicate...that a total loss of safety system function is not a rare event. For example, during January, 1984, a total of 7 actual failures of safety systems were reported. Further, over the past three years or so, a total of more than 120 total losses of safety system function have been identified by AEOD. Most events (70 percent) were caused by human factor-related causes. The systems most frequently affected were those associated with decay heat removal, containment spray, and ECCS."

Failures of safety systems are significant because they are frequently challenged: "Studies...show a frequent challenge rate to emergency equipment. For example, the reactor trip frequency during 1983 was about 6.5 trips/plant/year. In the month of January, 1984, a total of 29 scrams were reported. The principal causes of these scrams were component failures and personnel errors."

There were judgments in the NRC study about the quality of reports from operating plants. One said that these reports, and industry learning practices in general, are "much improved" over the pre-TMI practice but another comment was aimed at recent poor performance: "In the past, studies—particularly trends and patterns analyses—have been severely hampered by the nonuniformity and incompleteness of licensee reports. The new LER rule, which became effective on January 1, 1984, should help correct many of these problems..."

Overexposure of workers to radiation continues to be a problem, says the report. The number of incidents are small, it adds, but they are avoidable.

The report contained recommendations for action by NRC's regulatory branches to remedy the problems.



Nuclear power industry begins decommissioning old reactors

Robert Smock
Managing Editor

The nuclear industry is reaching retirement age. It now faces the problem of decommissioning its veteran nuclear power plants.

About half the commercial power reactors put on line in the '50s and '60s have reached the end of their lives already. The U.S. Department of Energy says 20 more units are expected to be "eligible" for decommissioning during the next 15 years.

One of the retired veterans, Shippingport, is slated for a formal decommissioning featuring a costly dismantlement and removal of all structures. Others, like PG&E's Humboldt Bay, are being decommissioned but are merely being closed for the time being. Still others, like Commonwealth Edison's Dresden 1 and Consolidated Edison's Indian Point 1 have been retired; a decision on formal decommissioning is being put off.

Other veterans like Yankee Rowe, Big Rock Point, Haddam Neck, and Monticello are still running strong, but in the words of a DOE official, they're "getting old."

Dan Williams, a member of the Atomic Industrial Forum's committee on decommissioning and a member of Arkansas Power & Light's nuclear operations division, told a recent nuclear meeting in Chicago that a full-scale decommissioning of a modern, large nuclear unit would cost from $140 million to $170 million.

According to Williams, the industry is not starting at zero to develop decommissioning techniques. "Nuclear plant decommissioning is an assured commercial industrial endeavor, not a research and development project."

To date, 68 nuclear reactors have been decommissioned, counting small research and experimental reactors, Williams said. That includes 9 small, non-commercial power reactors of which five were mothballed, three "entombed", and one dismantled.

DOE, says Williams, has published a handbook describing decommissioning techniques, such as concrete and metal structure removal, and the federal agency plans to publish a report early this year that will help utilities estimate the cost of decommissioning a specific unit.

The Shippingport project will bring decommissioning "to the brink of commercialization," according to Williams. He says that past projects have helped develop techniques but they've been relatively small scale. For example, the dismantlement of the Elk River experimental reactor, the largest dismantlement project to date, produced about 128,000 cubic feet of concrete waste. A typical commerical sized PWR, says Williams, has 4.5 million cubic feet of concrete.

Tearing down Shippingport

According to DOE, which owns the Shippingport reactor, little of the past work on decommissioning has demonstrated the techniques planned for this project.

Shippingport is a 72-MW PWR first operated in 1957. It was shut down in 1977 for conversion to operate as a light-water breeder, operated for three years in that mode, then stopped operating for good in 1982. Fuel was removed last summer and decommissioning activities started.

The goal is to return the site to "unrestricted" use. The plan is to "greenfield it," explains Franklin Coffman, director of DOE's office of waste disposal. Everything in the nuclear reactor part of the plant—the part DOE owns—will be removed.

Three feet of clean dirt on top of a clean rubble bed will be all that's left

Continued on page 22

PREVIOUSLY DECOMMISSIONED REACTORS

Reactor	Mode of decommissioning	Date of decommissioning
Hallam Nuclear Power Facility	Entombment	1968
Piqua Nuclear Power Facility	Entombment	1969
BONUS	Entombment	1970
Elk River	Dismantlement	1974
Peach Bottom	Safe storage	1978
Los Alamos Molten Plutonium Reactor Experiment	Dismantlement	1980
SRE (Sodium)	Dismantlement	1982

Source: DOE

POWER REACTORS ELIGIBLE FOR DECOMMISSIONING
Reactor Vessel Characteristics

Plant	Power (MWe)	Vessel size	Wall thickness	Activity (curies)	Weight (tons)	Comm. ops.	Type	Power generated (MWhrx10⁶)
Elk River	22.5	D=7.5' H=28'	3"	1.0×10^3	<90	1964	BWR	0.4
Shippingport	72	D=10.5' H=35'	8.4"	1.2×10^4	218	1957	PWR	7
Indian Point #1	265	D=10' H=33'	7"	3.5×10^6	225	1962	PWR	30
Humbolt Bay	65	D=10' H=40.5'	6"	N.A.	159	1963	BWR	5
Dresden 1	207	D=13' H=41'	5.5"sides 9"bottom	N.A.	–	1960	BWR	17
Yankee Rowe	175	D=10.5' H=31.5'	8"	N.A.	150	1961	PWR	24
Big Rock Point	64	D=9.7' H=30'	5.3"	N.A.	120	1963	BWR	7
Haddam Neck	582	D=13' H=42'	10.6"	N.A.	–	1968	PWR	59
Monticello	545	D=17' H=63'	5"	N.A.	–	1971	BWR	39*
Oyster Creek	650	D=18' H=64'	7.3"	N.A.	–	1969	BWR	44*
San Onofre	436	D=12' H=37'	9.8"	N.A.	–	1968	PWR	37*
Nine Mile Point	620	–	7"	N.A.	–	1969	BWR	43*
Vermont Yankee	514	D=17' H=63'	5"	N.A.	–	1972	BWR	31*

*As of early 1982

Source: DOE

If the barge carrying the reactor sinks in the Panama Canal "we'll probably have a cost overrun."

when the decommissioning project is completed in 1988, says Coffman. Uncontaminated underground structures will remain three feet below grade.

Unrestricted use is defined by DOE, says Coffman, to mean that less than 170 millirem/yr is contributed to the food chain. Vegetables can be raised at the site, says the official.

The project is estimated to cost $80 million in 1986 dollars. That's a lot compared to the original, 1957 price tag for the plant of $121 million. But, says Coffman, it's only about 10 percent of the 1986 replacement cost of that much capacity.

There were cheaper options than dismantlement, says Coffman. DOE could have just locked the door and walked away. Surveillance would have cost about $250,000 a year. Another option was to entomb the radioactive facilities by encasing them in a massive concrete structure.

One of the reasons DOE chose immediate dismantlement was its relationship with Duquesne Light. The utility owns the site and the non-nuclear facilities and has a lease agreement with DOE that expires in 1994. The site of Duquesne Light's Beaver Valley nuclear station is adjacent to the Shippingport site. According to DOE, the utility has made it clear that the only method of decommissioning acceptable to it is prompt dismantlement.

One-piece removal

A striking feature of the Shippingport dismantlement plan is the decision to remove the reactor vessel in one piece instead of cutting it up. The vessel, which is 35 feet high and 10.5 feet in diameter, will be filled with other radioactive components.

The 770-ton shielded package plus other radwastes from the project will be put on a crawler, hauled to the nearby Ohio River, and put on a barge. The package will be barged via the Ohio River, Mississippi River, and the Panama Canal to DOE's Hanford site in the state of Washington where it will be buried.

A major reason for choosing one-piece removal is the "institutional nightmare" of sending 80 loads of waste to Hanford by truck, Coffman explained. The single barge shipment will be able to handle all the waste.

The DOE decision was influenced by their experience with getting the waste out of the West Valley reprocessing facility, which DOE is currently cleaning up. Trucking out the radioactive material has been a "nontrivial" problem, said Coffman. DOE worried that some state or community would shut down the $80 million project. Coffman added that segmented removal of Shippingport structures would have raised project cost by $7 million.

Asked what happens if the barge sinks in the Panama Canal, Coffman said, "We'll probably have a cost overrun." He explained that a crane would be built and the load would be lifted out and set on the canal bank. The package, he added, is designed not to leak. He said it would be no more a problem than the UF_6 shipment that sunk in the North Sea recently. It can be dealt with, said Coffman, as long as it doesn't go off the Continental Shelf.

Asked if one-piece removal is applicable to larger reactor vessels, Coffman said it probably isn't. He noted that newer vessels are much larger than Shippingport's and that modern plants contain several orders of magnitude more radiation. He said DOE went with one-piece shipment, even though it may not be useful for larger plants, to reduce complexity and keep costs down.

Cooling off Dresden

Another major retirement-related project currently underway is the decontamination of Dresden 1.

Commonwealth Edison is not formally decommissioning Dresden 1 but has announced the unit is being retired and will not be operated again. Dresden 1 is the commercial prototype for boiling water reactors. It is a 200-MW unit first operated in 1960. It was operated successfully until 1978 when it was shut down for major modifications.

The accident at TMI occurred during the outage and the utility estimated the cost of bringing Dresden 1 into compliance with the post-TMI regs at $300 million. It did not want to spend that much on the reactor and it has not operated since then. Last August Commonwealth Edison announced the unit would be retired.

While the unit was still operating in the early '70s Commonwealth Edison had decided to decontaminate its entire primary system—an unusual step for a U.S. power reactor (see EL&P, November, 1984, page 42.) The decision was made because of the high radiation fields that were interfering with normal maintenance.

In a recent speech, David Harmer, president of the decontamination contractor for the project, IT Nuclear Services, said, "By that point in time (the 1978 shutdown), the various in-service inspections had been delayed to the point where it was no longer possible to run the reactor further until decontamination was completed."

The primary side decontamination was one of the major steps planned for the outage that was overtaken by events, including the decision not to operate the reactor any more. Objections by intervenors and delays imposed by the Nuclear Regulatory Commission, such as the requirement for an environmental impact statement, led Commonwealth Edison to put off the decision to proceed with the decontamination project in the early '80s.

However, the utility had already invested $50 million in the project, including $8 million from DOE. Most of it was for construction of a permanent decon facility at the Dresden site. The idea was to use it for periodic decontaminations of all three reactors there. A considerable amount of money and effort was also devoted to studies of the effect of the decontamination solvent on the materials at Dresden 1.

As a result Commonwealth Edison revived the decon project last year. The goal of the project now is to demonstrate the effectiveness of using a concentrated solvent on the primary side of a reactor and to serve as a preliminary step in the planned mothballing of the unit.

Irene Johnson, former project engineer in the program and currently working in Commonwealth Edison's communications department, said a decontamination factor of from 100 to 1000 was desired.

Johnson pointed out that Dresden 1

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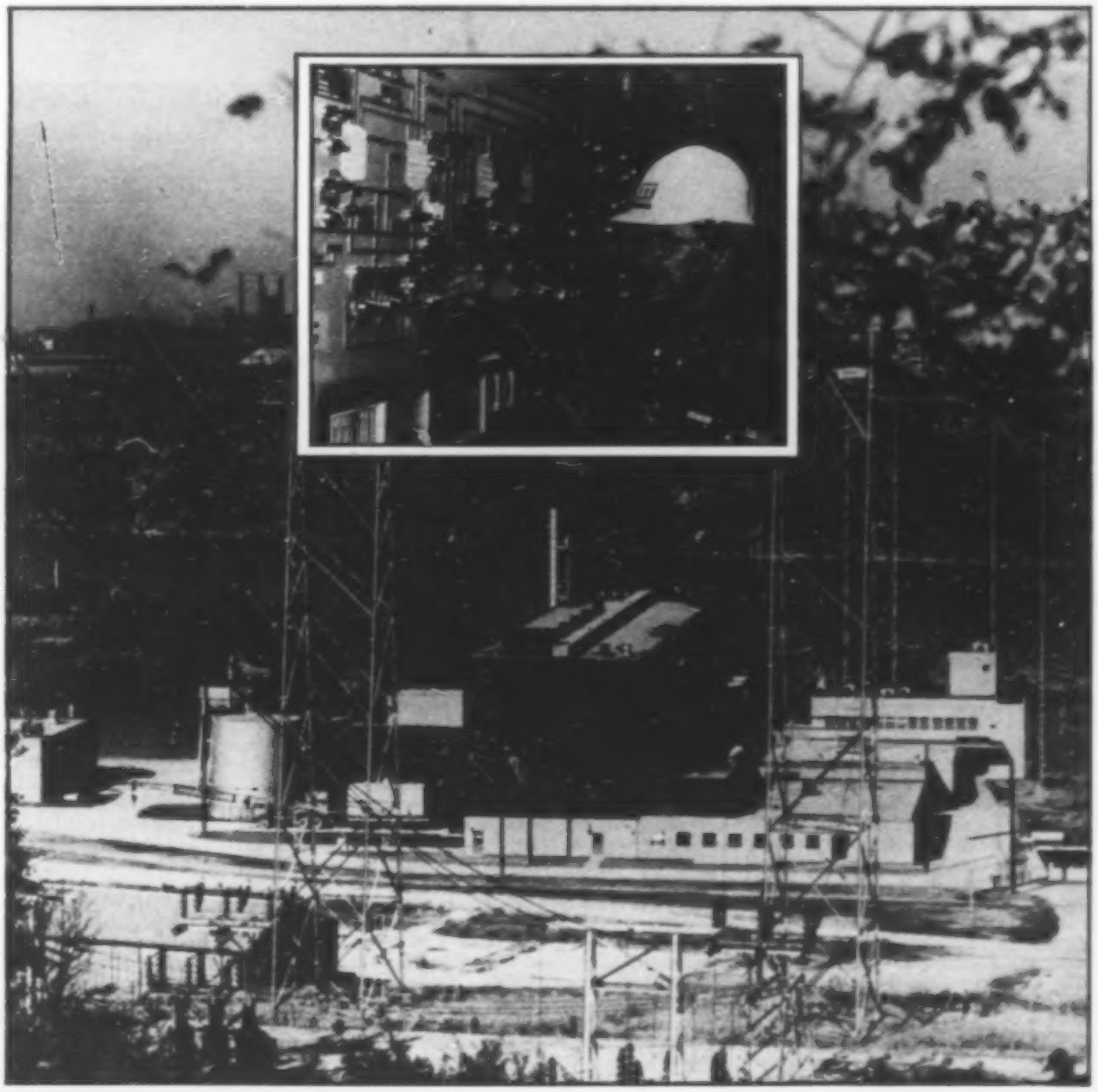

DOE has already begun the decommissioning process for the Shippingport reactor near Pittsburgh (below). Commonwealth Edison built a decontamination facility (inset) for its Dresden station where unit 1 is being retired.

Decommissioning . . . from page 22

has an unusual design for a BWR. It has a steam drum and steam generator loops. However, only the primary side of the system was decontaminated. Fuel was removed in 1978.

Last September 95,000 gallons of concentrated solvent (called NS-1) was pumped through the system, followed by rinses. The cleaning and flushing process took 100 hours, at a temperature of 255F.

The decontamination was more effective than expected, said Johnson. A total of 726 curies of Cobalt-60, the chief contaminant, came out in the decon solution; 667 curies had been expected. "We're very happy overall with the results," said Johnson.

The cleaning and flushing solutions were stored in two 250,000-gallon tanks on site. The radwaste will end up in the form of solidified ion-exchange resins in 55-gallon drums. A total of 468 drums will be buried at the Hanford site.

Johnson said there are still questions about future steps to be taken with Dresden 1. It's not being decommissioned because the site is still in use—the operating license for the newest unit, Dresden 3, doesn't expire until 2003. Now that it's clean Dresden 1 will get some kind of caretaking which hasn't been exactly defined yet.

"Safstor" for Humboldt Bay

A third alternative has been chosen for Pacific Gas & Electric's veteran Humboldt Bay unit 3. Shut down since 1976, the reactor will be put into a "safstor" condition for 30 years, then dismantled.

The 63-MW nuclear unit operated from 1963 to 1976 when it was shut down for seismic modifications. It never operated again and PG&E recently announced that it would be officially decommissioned.

The utility has applied to the NRC for a license amendment and in the meantime is preparing the reactor for the 30-year cold storage phase. Fuel was removed from the core last March and put in the on-site pool. Plant facilities are being decontaminated "to the extent practical to minimize the potential for spread of contamination outside of the facility and to minimize the requirements for periodic surveys," according to a recent presentation to the NRC by decommissioning project manager, Terry Nelson.

Plant systems are being flushed and drained. Radwastes are being processed and will be shipped out for burial. Nelson estimated the project would require about 100 low-level radwaste shipments.

Activities necessary to put the plant into cold storage are expected to be completed by the end of the year. The plant will then be guarded and monitored for an estimated 30 years when fuel will be removed from the site and final action taken.

Several other small power reactors have been shut down permanently. Peach Bottom 1, for example, was formally decommissioned like Humboldt Bay 3 and Shippingport will be. Indian Point 1, like Dresden 1, is just being defueled and permanently retired from service for the time being.

Premature decommissioning

The foregoing are reactors that were voluntarily removed from service by their owners because it was felt they had reached the end of their lives. There's another type of decommissioning, "premature decommissioning", that deserves a look.

The accident at Three Mile Island unit 2 produced the most recent, and most hope, the last example of premature decommissioning of a nuclear unit.

Franklin Coffman, the DOE official in charge of the decommissioning work at Shippingport and West Valley, also oversees the agency's interest in the TMI-2 cleanup and described it at a recent American Nuclear Society conference. He noted that advances in cleanup and decontamination procedures developed at TMI, the extensive use of robots is a good example, will help all utilities in their future decommissioning activities.

Coffman reported that radioactive contamination of porous cinder block and concrete surfaces at TMI is re-

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Decommissioning options, costs

The Atomic Industrial Forum reports that NRC regulations define three acceptable forms of decommissioning.

Mothballing, or safe storage, requires that the fuel be removed and the facility placed in "a state of protective storage with continuing confinement of radioactive materials so that the risk to the public is minimized and within acceptable radiation protection limits." Security and monitoring are required. Cheapest of the options, AIF estimates the costs (in 1980 dollars) at $3 million to $12 million for a PWR and $3.5 million to $20 million for a BWR.

Entombment requires that the fuel be removed and all highly radioactive components such as the reactor vessel sealed in "a protective structure of concrete or other high integrity material." Again, security and monitoring measures are required. Cost is estimated to range from $6.5 million to $41 million for a PWR and $11 to $38 million for a BWR.

Dismantlement requires that everything radioactive be demolished and removed from the site, permitting unrestricted use of the property. Cost is set at $24 to $102 million for a PWR and from $29 to $122 million for a BWR.

Combinations of the options may be acceptable, says AIF.

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NERC drops growth forecast to 2.5%/yr

HOUSTON—The National Electric Reliability Council's 10-year forecast rate for peak demand growth has declined for the tenth straight year, according to a report by the organization's engineering director David Nevius and publications manager Blaine Vincent made at the Coal Technology Conference.

In 1974 NERC's member utilities forecast a peak demand growth rate for the next ten years of 7.6 percent per year. As the realities of the following decade set in that forecast rate steadily declined. In its latest summary of utility forecasts, NERC shows an expected growth rate in peak demand for the period 1984-1993 of 2.5 percent per year, which is about what it actually was for the past ten years. Energy requirements are expected to grow at an average rate of 2.7 percent per year for the next 10 years, slightly below the actual growth rate for the last 10 years.

"This scenario," reported Nevius and Vincent, "is based, one must be cautioned, on the trend of the past ten years. But trends can change, as we have seen. If and when our current decade-long trend actually starts to change, all bets are off."

Noting the 5 percent growth in electrical energy consumption in 1984 over 1983, the NERC analysts said it's too early to tell if it's indicative of a new trend which would make the latest forecast too low. "Careful forecasters," said the analysts, "are witholding judgment for a few more quarters to watch developments."

They noted that NERC's forecast is finally in the middle of the other forecasts. It has traditionally been on the high side.

NERC's members expect capacity to grow at a rate of only 1.8 percent per year through 1993. If summer peak demand does climb 25 percent above the 1983 level to 559,000 MW as expected, 1983's 35 percent reserve margin will drop to about 28 percent.

Overall, generating capacity is expected to rise by 130,000 MW during the next ten years. Of that total 85 percent will be coal-fired and nuclear capacity. Utilities plan to add 55,000 MW of nuclear capacity (average unit size is 1100 MW) between now and the early 1990s after which nuclear capacity additions stop. Coal-fired plants to be added over the next ten years total 56,000 MW (average unit size is 526 MW.)

Total generation is expected to rise by 30 percent to reach 3 million GWhr in 1993. Coal's share of 1993 generation is forecast to drop slightly to 54.6 percent from 1984's 55.9 percent. Even though its share drops a bit, total coal consumption by utilitites is expected to grow 27.7 percent, from 646 million tons in 1984 to 826 million tons in 1993.

Conversion of capacity currently burning oil to burn coal is expected to account for 10 percent of the growth in coal consumption. Close to 6000 MW of capacity is slated for conversion, 70 percent of which is in New England or New York.

Nuclear's share of 1993 generation is expected to rise sharply to 23.6 percent of the total from 1984's 15.9 percent. The share for oil and gas combined is expected to drop to 25.8 percent in 1993 from 1984's 32.2 percent. Hydro's share is also expected to drop slightly to 9.4 percent from 10.4 percent in 1984.

Utilities also plan to add 26,000 miles to the existing 132,000 miles of bulk power transmission networks.

TVA director calls for acid rain action

KNOXVILLE, TN—Legislative action should be taken to control acid rain, urged Tennessee Valley Authority Director John B. Waters before members of an environmental group in Nashville.

Waters said, "I am satisfied that there is sufficient evidence of a causal connection between fossil fuels and acid depostion to warrant further restraints on sulfur emissions, and I hope that Congress will take appropriate action."

He said that absolute certainty about causes and effects of environmental problems comes "only when our resources are absolutely destroyed."

Citing apparent acid rain-related damage to forests in West Germany and lakes in Scandanavia, Waters said that we can't "wait until our own forests are blighted and our lakes are dying before we take steps to protect them."

He said TVA has shown that sulfur pollution control can be achieved.

Decommissioning . . .

from page 33

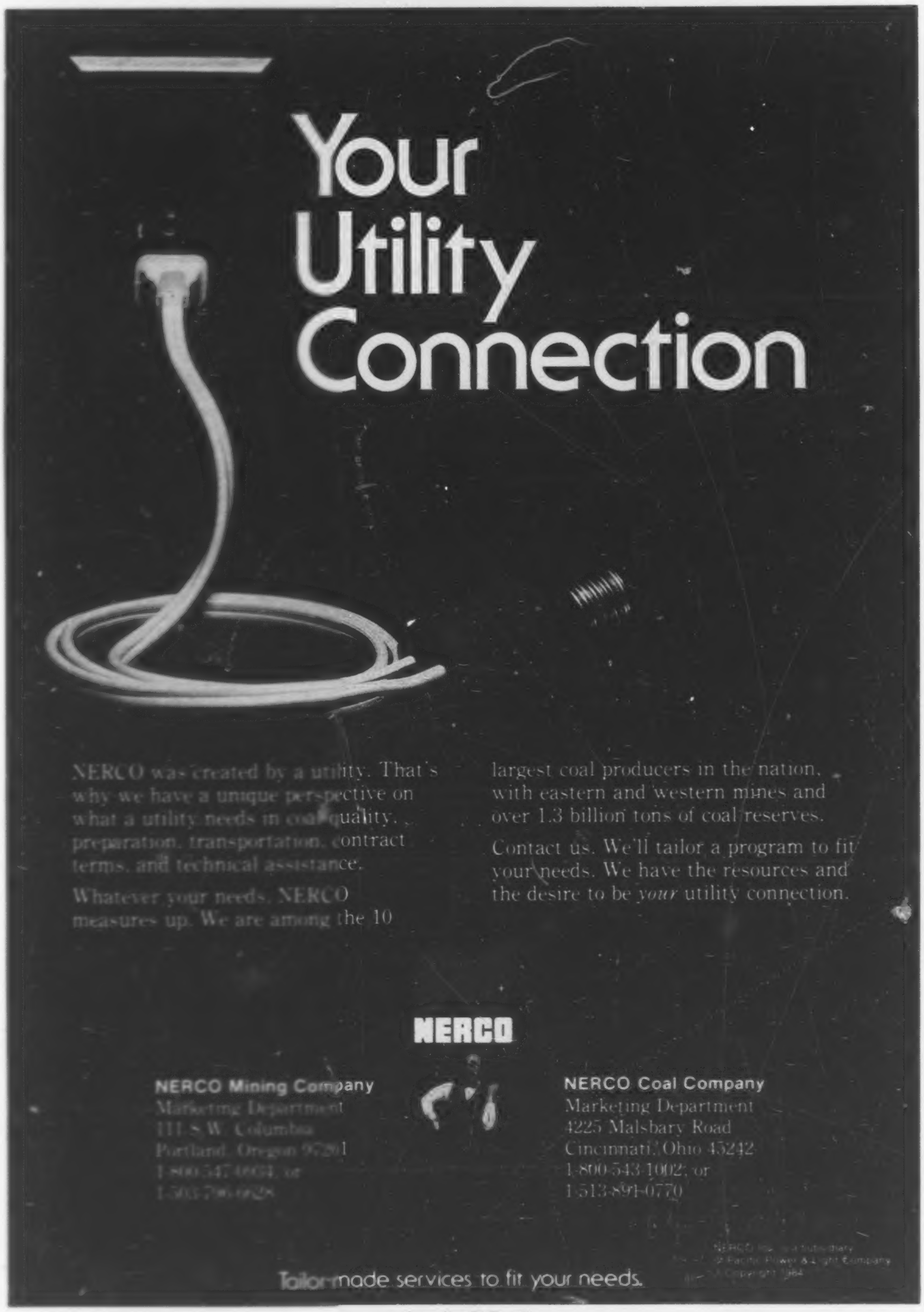
quiring an enormous effort to remove the top layer of concrete. None of the concrete was sealed or painted, he said, adding, "There ought to be a message there."

The porous cinder block walls at the bottom of the plant structure are the hottest areas remaining, at about 1000 R/hr. About 75 percent of the reactor building surfaces have been decontaminated so far.

Present schedules call for removal of the damaged core in 1987. The plan is to package the 300,000 lb of core material in canisters and ship it to Idaho for storage, pending final disposal in the geologic repository to be built by the federal government.

Cleanup funds are currently being spent at the rate of about $100 million a year. The total effort is estimated to cost $760 million. The unit cost about $700 million to build.

However, TMI-2 aside, decommissioning appears to be a manageable issue for utilities. The older reactors are being taken out of service and decommissioned in an orderly way at what appears to be, so far, a reasonable cost.



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Volume 63, Number 2
February 1985

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

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Send research dues directly to EPRI, says EEI board

SCOTTSDALE, AR—The Edison Electric Institute Board of Directors has voted to recommend to its member companies that they pay their Electric Power Research Institute dues directly to the institute and no longer use EEI as an administrative conduit.

The board action comes as a direct result of a public challenge by the Environmental Action Foundation to the EEI practice of collecting EPRI dues before passing them on to the institute. EAF charged that EEI has been able to secure and keep for its own purposes from $14 to $19 million in interest payments since the practice began in 1972. The group called upon EEI to stop this "skimming," and to turn over to the research institute all the interest it had earned from EPRI funds over the past decade or so.

Although the EEI board has voted to recommend that EPRI collect its future dues without institute help, it did not address the issue of returning the interest money it has already collected. EEI, therefore does not plan to refund the money, an institute spokesperson said.

The EEI source also vehemently denied the Environmental Action Foundation's calculation that the institute had collected between $14 to $19 million over the past 10 years. This figure was inaccurately arrived at, EEI maintains, by simply multiplying the current estimated interest figure of about $1.6 million by 10. The growing EPRI budget over the years makes the calculated $14 to $19 million figure too high, EEI says.

No EEI estimate

The institute itself, however, had no estimate on how much interest income it has collected over the period.

"It is disturbing to both consumers and regulators that funds collected from consumers for research by another organization have apparently been used to support the lobbying and advocacy functions of EEI," EAF research coordinator Richard E. Morgan said in a November 25, 1984 letter to EEI president William McCollam, Jr.

An EAF press release announcing Morgan's letter to McCollam estimated EEI's annual costs of handling EPRI funds at $14,000.

In a recent rate hearing of the Wisconsin Electric Power Company before the state's Public Service Commission, EEI's Dr. Douglas Bauer acknowledged that the current annual EPRI interest income, as a percentage of EPRI dues payments, would fall between $1.4 million and $1.8 million. Bauer also stated that EEI administrative costs for handling EPRI dues would be "substantially less than the $1.4 to $1.8 million."

In a December 31, 1984 letter responding to the EAF charges—a letter sent to all state utility commissioners—EEI's McCollam explained that EEI, as a matter of good business practice, invests all surplus funds on a short-term basis. The interest from these investments, he said, is combined with interest from longer term investments and togeth-

Continued on page 6

EEI sends $10.9 million to TMI-2 cleanup fund

WASHINGTON, D.C.—In late December, the Edison Electric Institute (EEI) sent its first contribution from investor-owned utilities to the cleanup of the damaged Three Mile Island Unit-2.

EEI spokesperson Gloria Dittus said the institute sent a check to the fund for approximately $10.9 million.

The EEI board adopted a resolution in January 1983 to collect $150 million ($25 million a year for six years) in voluntary contributions from investor-owned utilities.

However, as of late 1984, only $66 million ($11 million per year) had been pledged by 33 utilities for the clean-up fund. That left $84 million still to be found.

Compromise plan

The EEI Board of Directors recently devised a two-part compromise plan whereby six utilities in Pennsylvania and New Jersey will make up the $84 million shortfall over six years by diverting money that would have been sent to the Electric Power Research Institute to the TMI-2 fund.

EEI President William McCollam said, "These two parts are the 'industry voluntary program' and the program of supplemental research and developmental grants from six Pennsylvania and New Jersey utility companies. The supplementary program assures that the full level of $25 million per year for six years, for a total of $150 million, will be available for the cleanup effort."

The six utilities are General Public Utilities, Pennsylvania Power & Light, Duquesne Light, Philadelphia Electric, Public Service Electric & Gas and Rockland Electric. Atlantic City Electric, while not an EPRI member, will participate in the supplemental plan.

Money for the supplementary program will be provided from funds that would have otherwise been paid as EPRI dues, according to EPRI. In 1985, the supplementary program will be paying $14 million to the cleanup in quarterly installments.

Three will leave

According to spokespersons from EPRI and EEI, three of the six utilities will drop out of EPRI this year and contribute to the fund, while the other three remain EPRI members. Then, in 1986, their roles will be reversed. At press time, it had not been determined which utilities would be dropping out of EPRI this year.

"The mix of funds from these two sources for future years may vary as participation in the industry voluntary program is increased," said McCollam.

EEI hopes that more utilities will join the 33 that already have pledged to support the voluntary program.

EPRI spokesman Dan Van Atta said that even though the utilities leaving the organization to participate in the program will "technically" be non-members, EPRI will still retain its relationships with the utilities.

EPRI Senior Vice President of Finance and Administration David Saxe said that the utilities in the supplementary program may still receive free EPRI publications and some of the groups' services, but will not be able to nominate members to the EPRI technical advisory committees during their participation in the TMI funding plan.

GPU said that contributions to the

Continued on page 6

Shoreham loads fuel despite major license obstacles

BROOKHAVEN, N.Y.—Long Island Lighting has been granted authorization to load fuel at its beleaguered Shoreham nuclear plant despite serious obstacles that continue to cast doubt on whether the plant will ever operate commercially.

At press time the company said it expected to complete fuel loading by February 1.

On December 7, 1984 the Nuclear Regulatory Commission okayed the company's request to load fuel and conduct precriticality testing at Shoreham. The NRC also approved cold criticality testing. These authorized activities represent the first two phases of a four-phase nuclear plant startup regime. Phases 3 and 4, which include low power testing to one and five percent of rated power, respectively, are still under review by the federal regulatory commission.

The major hurdle facing Lilco in getting Shoreham on-line continues to be the refusal of Suffolk County to approve an emergency evacuation plan. The county has resolutely contended that in the case of a serious accident at Shoreham it would be impossible to safely evacuate or otherwise protect the public.

The county is joined by the Governor of the state in resisting the approval of the emergency evacuation plan.

NRC's decision called political

In a mid-summer memorandum and order, the NRC stated that "The commission found that 10CFR50.47 (D) established unqualified authorization [for it] to issue a low-power license without the need for a predicitive finding . . .that a full power license will ever issue."

In short, the commission believes it has the statutory authority to issue a low-power license without concerning itself with whether Lilco will ever qualify for a full power license. On December 7 it implemented that authority.

Some important segments of the nuclear community don't agree with

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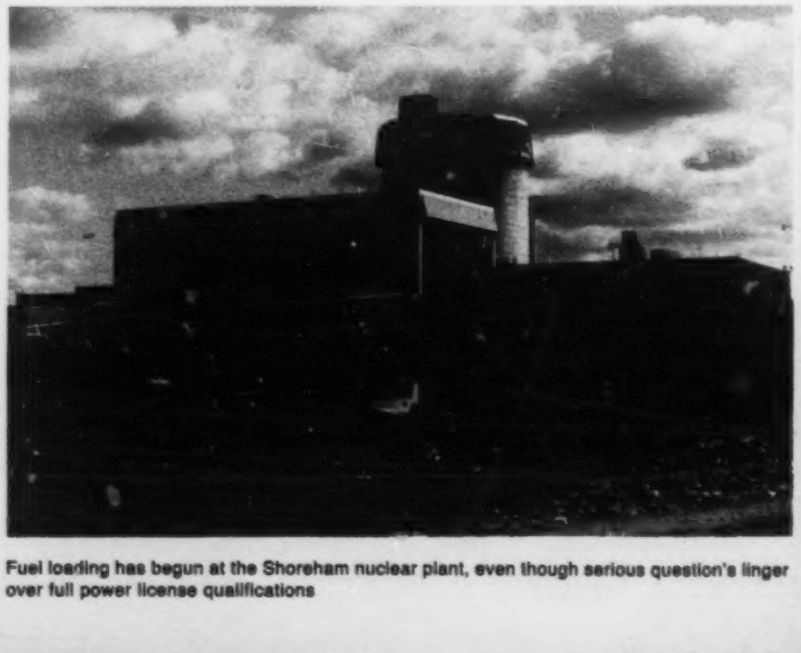

Fuel loading has begun at the Shoreham nuclear plant, even though serious question's linger over full power license qualifications

Foreign Power Briefs

- **Solenergy Corporation** said it signed a letter of intent with the Tianjin, China No. 2 semiconductor manufacturing plant to make solar cells for the plant using material supplied by the Tianjin concern. Solenergy and Tianjin also agreed to study the feasibility of forming a joint venture manufacturing facilitiy to manufacture and market solar cell modules on a world-wide basis.

- **Ontario Hydro** reports that its customers earned over $13 million in November from the sale of 806.4 million-kWh of electricity to the United States. The utility said November export earnings were 25 percent higher than in the same month in 1983.

- **Westinghouse Nuclear International Europe** said it will build a $5 million European Service Center near Brussels, Belgium to provide maintenance and repair for electric generating plants in Europe. Westinghouse Nuclear International President Carlo L. Caso said the company will be able to serve its European customers more quickly and responsively. He siad the center, which should be completed by late 1985, will be positioned to service most of the plants in Europe within less than a one-day drive.

- **Delegations from China and Argentina** will be visiting the U.S. in early 1985 to learn more about the potential uses of wind energy, according to the U.S. Department of Commerce. The group from China will visit in late February or early March and will be composed of persons from the province of Inner Mongolia. The Argentine delegation will visit sometime early this year. The Commerce Dept. said the Argentines are interested in talking with wind system manufacturers and visiting wind research centers.

HL&P audit finds potential savings

HOUSTON—An independent management audit of Houston Lighting & Power Company has discovered potential cost savings of $24 million, said the utility.

Arthur Young & Company, who conducted the audit, said that it found HL&P's organizational structure and decision making processes to be well-managed and effective.

A new Texas Public Utilities Commission law requires all public utilities to undergo a management audit. The report to HL&P contained 83 recommendations.

HL&P President Don Sykora said, "HL&P is preparing detailed action plans to address each of these recommendations and has indicated to the PUC that it will implement all recommendations where benefits exceed costs."

Said Arthur Young in its report, "An effective electric utility manages critical business issues, controls construction costs and secures a sufficient supply of fuel at reasonable prices. HL&P meets these criteria and in our judgement is effectively managing the essential, core functions described above. The executive management is sound and in a continuing state of improvement."

The audit team also said it found HL&P's South Texas Nuclear Project to be well-managed. "The STP schedule is an aggressive but achievable one. STP methods for planning and control are adequate in light of project needs," said the auditors. "They incorporate state-of-the-art technology in project management and software."

The audit will prove to be helpful to HL&P management and our custormers, said Sykora.

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Preliminary sites picked for waste depository

WASHINGTON, D.C.—Sites in Nevada, Texas and Washington have been identified by the U.S. Department of Energy (DOE) as possible locations for the country's first permanent geologic repository for high-level radioactive waste.

DOE recommended in December that further site characterization be conducted at Yucca Mountain, Nevada (tuff); Deaf Smith, Texas (bedded salt); and Hanford, Washington (basalt flows). The host rock of each site is in parentheses.

Site characterization includes construction of exploratory shafts to depths of a proposed repository (approximately 1,000-4,000 ft underground), in order that data can be collected and analyzed.

Advantageous combination

In a draft environmental assessment of the sites, DOE said it "...believes that the Deaf Smith, the Hanford, and the Yucca Mountain sites offer, on balance, the most advantageous combination of characteristics and conditions for the successful development of a repository and should therefore be recommended for characterization."

The recommendations are being made because of requirements of the Nuclear Waste Policy Act of 1982. DOE identified nine potential sites for the repository in Feb. 1983 and then had to nominate five of those sites for site characterization. The first repository is scheduled to begin operation in 1998.

In addition to the three recommended sites, DOE said other potentially acceptable sites are located in Richton Dome, Mississippi (domal salt) and Davis Canyon in Utah (bedded salt).

The four sites that weren't nominated from the original nine are Vacherie Dome in Louisiana (domal salt), Cypress Creek Dome in Mississippi (domal salt), Swisher County in Texas (bedded salt), and Lavender Canyon in Utah (bedded salt).

DOE said the proposed geologic repository will take up about 2000 acres at a depth of 4,000 feet. Surface facilities to handle and process the waste will occupy approximately 400 acres. After operating for between 25-30 years, DOE said the site will be closed and sealed.

Based on current nuclear generating capacity, DOE estimates that there will be 50,000 metric tons of spent fuel in the U.S. by the year 2000.

Assessments available

Draft environmental assessments for all nine sites are available for a 90-day period that began in December. DOE has scheduled public hearings in each of the states where recommended sites are located.

After the hearings are completed and all public comment is received the department will issue final environmental assessments.

The site characterization process is expected to take four or five years. DOE will recommend one site to the President, which he has the option of recommending to Congress in 1990.

DOE explained that the host state may issue a notice of disapproval that can be overridden only by a Congressional resolution. If the resolution isn't passed, the President must submit another site nomination to Congress within 12 months.

Requests for copies of the draft environmental assessments can be made by calling (800) 858-1600.

NARUC subcommittee

In a related matter, the National Association of Regulatory Utility Commissioners (NARUC) voted to form a standing Subcommittee on Nuclear Wasted Disposal of the Committee on Electricity at its recent annual convention in Los Angeles.

NARUC said the subcommittee will be responsible for providing DOE and Congress "its unique expertise in matters of finance, hearing processes and utility regulation so as to improve the (waste disposal) program and assure that ratepayers' funds to support the program are used effectively...".

Also, the NARUC subcommittee will be responsible for providing all regulatory commissioners information on the waste program.

WPPSS-2 enters service

Washington Public Power Supply System's Plant-2 in Washington began commercial operation December 13. The 1,100 MW General Electric boiling water reactor is not scheduled for an outage until April. The plant is supplying power to the Bonneville Power Administration.

Four new nuclear plants enter commercial service

WASHINGTON—Four new nuclear power plants started commercial operation in 1984: South Carolina Electric & Gas Co.'s Summer unit 1, Duke Power Co.'s McGuire unit 2, Southern California Edison's San Onofre unit 3, and Washington Public Power Supply's Plant 2.

That brought the total number of operable nuclear plants to 88 and there are 39 more with construction permits. "This was the year that many logjams in nulcear licensing were finally broken," said Carl Walske, president of the Atomic Industrial Forum. In addition to the four plants going commercial, five more received full-power licenses in 1984 and are nearing commercial operation, probably in 1985.

"It is possible that we are beginning to see the end of lean times," said Walske.

AIF predicted that the commercial units in 1984 accounted for 14 percent of U.S. electrical output, producing a nuclear electricity record of 325 billion kWh. Nuclear electricity output climbed 13 percent in 1984 while overall electricity production was up four percent.

In its annual year-end review of the nuclear industry the trade association noted that an AIF Study Group on the Economics of Coal and Nuclear Power reported in 1984 that future nuclear electricity can be cheaper than coal-produced electricity if project construction periods are no more than eight years.

Construction durations averaged 11 years for the plants going commercial in 1984 as shown in the table.

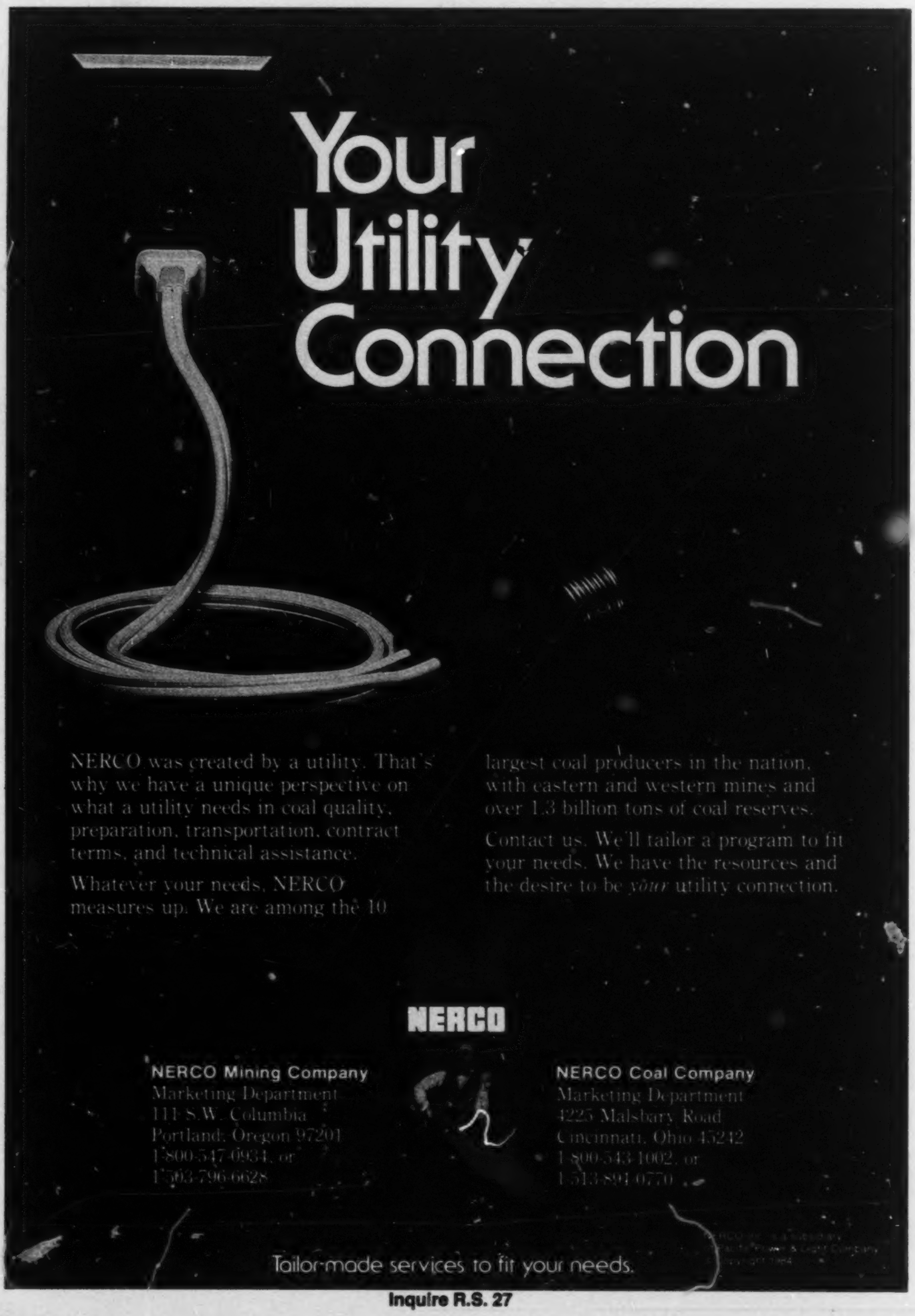
AIF said shorter construction times will become common with a "more stable licensing environment."

Said Walske, "Given the considerable progress the industry has made in improving its operations, we expect to see a move toward greater stability in the regulatory process. This is a prerequisite to orders for additional nuclear plants."

U.S. NUCLEAR PLANTS ENTERING COMMERCIAL OPERATION IN 1984

Plant	Size-MWe	Type	Utility	Const. permit	Operating license	Commercial operation	Construction duration
Plant 2	1,100	BWR	Washington Public Power Supply	3-73	12-83	12-84	11 yr. 9 mos.
Summer 1	900	PWR	S. Carolina Electric & Gas S. Carolina Public Service Auth.	3-73	11-82	1-84	10 yr. 10 mos.
McGuire 2	1,180	PWR	Duke Power	2-73	5-83	3-84	11 yr. 1 mo.
San Onofre 3	1,100	PWR	Southern California Edison	10-73	11-82	4-84	11 yr. 6 mos.

Source: WPPSS



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Coal industry predicts '85 consumption will rise

WASHINGTON—Consumption of coal in the U.S. is expected to rise 2.3 percent in 1985 to a record 805 million tons, according to the National Coal Association, trade association of the nation's coal producers.

Coal industry production, however, will decline by 1.1 percent as customers—chiefly utilities—work down their inventories. NCA says coal users built up inventories in anticipation of a miners' strike last fall.

NCA forecasts that utilities, which account for three-fourths of coal consumption in the U.S., will boost consumption in 1985 to 677 million tons, from 1984's 660 million. NCA expects electricity sales to rise 2.5 percent in 1985 and coal to account for 55 percent of electricity production.

Nuclear ambiguity . . .

from page 14

mal procedure in place regarding nuclear power plant cancellations. According to Thomas Novak, assistant director for licensing, a lot has to do with individual company situations and whether or not the nuclear utility is in on-going proceedings when it decides to terminate its nuclear plant. In most cases, he said, the construction permits are revoked during the hearing process.

Absent an on-going hearing, some kind of formal notification to the NRC is necessary to change the company's license status. When Cincinnati Gas & Electric announced it was cancelling its Zimmer nuclear plant, it explicitly declared "We will be filing with the Atomic Safety and Licensing Board, in the near future, the appropriate legal papers for withdrawal of the application" for an operating license.

Ultimately, for the termination process to be official, an applicant's construction permit or operating license has to be revoked by the NRC. But short of this action, it is often very difficult to discern not only the utility's long-range intention but the NRC's actual license status of the plant at issue.

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Volume 63, Number 3
March 1985

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

© TECHNICAL PUBLISHING

New financing accord may brighten Seabrook outlook

'Measure of confidence' restored in financial integrity

MANCHESTER, NH—Public Service of New Hampshire, major owner in the troubled Seabrook-1 nuclear plant, announced in late January that it had agreed to a new financing plan aimed at enhancing its ability to complete the nuclear unit.

Merrill Lynch, who was earlier retained by the Seabrook joint owners group to draft and implement a three-phase financing plan for PSNH, has now been joined by Drexel Burnham Lambert and Kidder Peabody. All three underwriters will revise the third step in the so-called Newbrook financing plan and together will sell securities under what is seen to be a more traditional scheme.

"Progress at the Seabrook station [over the past several months], and the successful completion of the first two phases of the plan by December 6, 1984, have begun to restore a measure of confidence in the financial integrity of the company," the underwriters testified before the New Hampshire Public Utilities Commission recently. "Accordingly, a more conventional structure now appears feasible for the third phase of the plan."

The three underwriters envision issuing two types of securities: deferred interest bonds that will be issued directly by PSNH, and, to the extent possible, tax-exempt pollution control revenue bonds issued by the Industrial Development Authority of New Hampshire. Both types of securities will be secured by a third mortgage on the PSNH properties.

PSNH currently estimates that it will need $332.6 million for its share of Seabrook completion. Under a previous proposal, a $665 million financing was contemplated where PSNH would have had to raise the first two years' interest at the time of the initial public offering. The new deferred interest feature allows a reduction of about $250 million in prefinanced interest.

There is also a corresponding reduction in the amount of cash the company must raise: the total face amount of the financing is reduced from $665 million to $525 million, a reduction of $140 million. Also saved is the interest on this $140 million over the remaining eight-year life of the financing.

According to PSNH's yearly statement of earnings, as of November 1984, total electric revenues for the company rose 15.5 percent over 1983,

Continued on page 2

New operating record for Oconee 2

Duke Power Company's Oconee 2 nuclear unit has set a new world record for continuous operation, surpassing the old record of 417 days on January 29 and as *EL&P* was going to press was approaching its goal of 441 days before being brought down for refueling on February 21. The 860-Mw Babcock & Wilcox unit posted a 100 percent availability factor and a 96.6 percent capacity factor for the entire year of 1984. See page 6 for other coverage.

Kwh sales per real GNP: the slide continues

WASHINGTON—Even though electricity demand increased measurably in 1984, it did not keep pace with the domestic growth in the gross national product (GNP). Last year, therefore, saw a continuation of declining electricity generation per constant (1972) dollar of GNP. The trend began in 1976, with 1980 as the only exception (see accompanying graph).

Specifically, electricity generation rose from 2,310 billion kilowatt-hours in 1983 to 2,415 billion kilowatt-hours last year, or an increase of 4.5 percent. Real, or inflation adjusted GNP (in 1972 dollars), rose from $1,534.7 billion in 1983 to 1,637.9 billion in 1984, a 6.7 increase.

The accompanying chart shows the ratios of electricity generation to GNP since 1976. It can be seen that 1984 represents the lowest ratio recorded since the downward trend began in 1976.

Helping to moderate electricity growth last year was the fact that weather conditions returned to more normal levels. Electricity growth was stimulated in 1983 by an extremely cold winter and an unusually warm summer.

However, according to Energy Information Administration economist Colleen Cornett, even if weather last year had approximated the weather a year eariler, the ratio of electricity generation to GNP would still have declined relative to 1983.

In the electric utility industry, the kWh/GNP measure has long been a key determinant in predictive efforts of future demand. In fact, according to a recent report by the Energy and Environmental Policy Center at Harvard University, economic growth was shown to be the most important determinant of electric demand. According to the study, only about 30 percent of the recent slowdown in electricity demand is attributable to price effects. The rest is the result of poor economic performance.

A recent report by the Congressional Research Service notes that the argument among experts over electricity growth and gross national product is not over whether a relationship exists, but over the nature of that relationship.

"These arguments are of more than academic interest," notes the CRS report, *Gold at the End of the Rainbow: A Perspective on the Future of the Electric Utility Industry*. The report points out that a demand forecast

Continued on page 6

Administration's 1986 budget request cuts energy spending

WASHINGTON—Spending by the U.S. Dept. of Energy on Energy R&D got only a light trimming in the fiscal 1986 budget proposed by the Reagan Administration. In the past the administration has proposed huge cuts in DOE's energy funds only to have Congress restore most of the cuts. This year the requested cuts are more modest.

The total DOE budget does contribute to cutting the deficit with proposed spending down about $2 billion, compared to outlays in the current fiscal year. However, that reduction results largely from the elimination of spending on the Strategic Petroleum Reserve. The administration reported that there is oil in storage equivalent to 108 days of imports at the projected 1985 import rate, allowing an "indefinite moratorium" on further additions.

There isn't much change in the rest of the DOE budget, with slight increases in the defense and nuclear waste areas offsetting slight decreases in areas such as energy research and development.

The total proposed DOE budget for fiscal 1986 is $12.5 billion, down from $14.3 billion in the current year. The overall proposal for government spending is a 1.5 percent increase to $974 billion, an increase so small compared to increases in the past decade that it is, in effect, a "freeze," according to the administration.

To put the DOE budget in long-term perspective, it should be compared to the budget projected by Carter administration for fiscal 1982, which would have been the first year of Carter's second term had he been re-elected. The Carter DOE would have spent $16.5 billion in 1982, of which more than $3 billion would have gone to energy research.

EL&P readers will recall that the newly elected Reagan administration wanted to completely eliminate DOE and proposed to slash its budget drastically in the meantime. Total spending was to be cut nearly $3 billion in the first year, with further large cuts slated for future years until elimination of the department was achieved.

The administration has not been too successful in getting what it wants at DOE. The idea of elimination is still alive, but just barely. Spending has been cut, but not nearly as much as hoped for.

Congress has fought a fairly successful holding action to keep its favorite DOE energy programs alive (while successfully killing some favorite administration energy projects such as the Clinch River Breeder Reactor.) In the energy R&D area, spending is still about half what it was during the peak Carter years. The administration wants to spend about $1.6 billion on energy R&D next fiscal year, down from about $1.8 billion in the current year. Specific areas:

- Spending on fossil R&D is projected at $242 million next year, down from $347 in 1985. Historically, this is one of the biggest losers in the Reagan DOE—Carter's DOE planned to spend $1.6 billion on fossil-related R&D in fiscal 1982.
- Nuclear R&D is projected to get $372 million, down from $416 million this year and $722 million in '82.
- Solar R&D spending is set at $148

Continued on page 2

Foreign Power Briefs

● **Four African countries** will be receiving the help of a Michigan electrical engineer in examining alternatives for more efficient electrical power distribution systems. The Michigan Dept. of Commerce and the Michigan Energy and Resource and Research Association selected William Moylan of Moylan Engineering Associates, Inc. to examine the distribution systems of Nigeria, Cameroon, Ivory Coast and Gabon. Both Michigan groups hope the venture will result in new business opportunities for state companies in Africa. All four countries, which rely mainly on hydropower, face a reduction in economic development due to a long-term drought that has hampered power production and distribution.

● **A report by France's Ministry of Industrial Deployment and Foreign Trade** concludes that new nuclear plants entering service in 1992 would produce cheaper electricity than a coal-fired plant starting up at the same time. The Atomic Industrial Forum said data from the report shows that electricity from a 1,300 MW nuclear plant would cost 22-23.5 centimes (2.4 cents) per kilowatt-hour. The report said it would cost 26-36.5 centimes for a 600 MW coal plant and 31-39 centimes if the plant was equipped with scrubbers. According to the French study, the nuclear plant would retain its advantage over a coal station, if it operated at a capacity factor more than 18.8 percent.

● **The People's Republic of China** and Flow Industries of Kent, WA have reached an agreement similar to a letter of intent for the construction of a $12 million windfarm, according to the American Wind Energy Association (AWEA). The group reports that FloWind has had extensive discussions with the Chinese about the project. Current plans call for 60 turbines to be installed at a site that has not been chosen yet. FloWind told AWEA that the wind machines could supply enough electricity for 160,000 homes.

● **Nuclear reactors in Western Europe** have been operating at an average annual capacity factor of ten percent or more above U.S. reactors in recent years, according to a new report. Jacques Le Clerq of Electricite de France, Hermann Kraemer of Nordwestdeutsche Kraftwerke and Franz Marcus of the Nordic Liaison Committee for Atomic Energy presented their paper at the American Nuclear Society winter meeting. The authors said that West European average annual capacity factors since 1976 have been between 68 and 78 percent, while U.S. capacity factors have hovered between 57 and 60 percent.

● **Pravda** has reported that Zaporozhe-1, a 1,000 MWe pressurized water reactor, went critical in early winter. The plant is the first of the Soviet Union's planned six 1,000 MWe PWRs at the Zaporozhe site in the Ukraine.

● **Switzerland and Egypt** have agreed to cooperate in the peaceful utilization of nuclear energy, according to *Nuclear Engineering International*. The magazine said it is the first agreement Switzerland has signed with a Third World country. According to the publication, China and India also have signed a similar agreement.

● **The People's Republic of China** has selected Stone & Webster Engineering Corp., to evaluate a 490-ft-high concrete arch dam that will be part of a major hydroelectric facility on the Second Songhua River in Jilin Province. Stone & Webster said it will develop computer models to assess how the dam will behave under different loading conditions.

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New Seabrook financing . . . from page 1

while total operating expenses rose 13.3 percent. Net income was up 7.6 percent with allowance for funds used during construction, dropping from 93.3 percent of net income to 92.9 percent.

At a regular meeting on January 17, in compliance with the New Hampshire PUC order, the company voted to omit dividends for both common and preferred stock that would have been payable on February 15, 1985. It also voted to omit a sinking fund payment on four series of perferred stock scheduled for May 15.

Robert J. Harrison, PSNH president and chief executive officer, said that notwithstanding the company's recently-completed $425 million financing, cash flow remains tight.

"Our recent successful financing is intended to satisfy the company's external cash needs, excluding its Seabrook station obligations, until Seabrook-1 is operating," Harrison said. "An additional financing will be necessary to satisfy our Seabrook obligations."

In a related development, New Hampshire Yankee received approval January 31 from the Nuclear Regulatory Commission to assume primary responsibility for the construction of Seabrook.

According to New Hampshire Yankee chairman Edward A. Brown, the NRC okay "is a major step toward establishing New Hampshire Yankee as an individual corporation—separate from Public Service of New Hampshire."

New Hampshire Yankee was formed as a division of PSNH by the 16 joint owners of Seabrook last June. The new organization will remain a division of PSNH until it receives final NRC approval as a separate corporation.

New Hampshire Yankee receives its direction from the executive committee of the project's joint owners.

"These factors, coupled with a shorter repayment term, will provide significant savings on a present value basis," PSNH testimony filed before the state PUC maintains.

Given deferred interest bonds, PSHN spokeswoman Carolyn d'Entremont said that the $525 million face value of the bonds will be discounted when sold. Because no interest will be paid for the first two years, the bonds will be sold for $340 million, a difference of $185 million. "This discount is designed to approximately equal the interest which otherwise would have accrued on the bonds during that two-year period," the PHSN testimony explains. "Interest will accrue after the two-year period and will be payable semi-annually."

The company expects that the third mortgage bonds will have maturities of between eight and 12 years and that there may be a sinking fund. And based on current market conditions, the underwriters estimate an interest rate (yield to purchaser) in the range of 19 percent to 23 percent.

There is some question whether, as a supplemental aspect of the new financing plan, the underwriters will be able to arrange the sale of pollution control revenue bonds. The company reports that if this tax-exempt financing is not feasible, the entire issue will consist of deferred interest bonds.

The underwriters say they are optimistic that they will be able to sell these discounted securities for PSNH. They cite the $425 million of debentures sold by PSNH last year and the witnessing by the financial community of construction activity increasing from zero expenditures last July to $5 million a week in December.

Further, the financial community is said to perceive the nuclear utility industry as recovering. "This new perception is reflected in higher prices in the secondary market for securities issued by most nuclear utilties," the underwriters say.

Finally, the underwriters point to the "substantial progress" of the other Seabrook joint owners in financing their shares in completing unit 1 and to the improve liquidity of PSNH.

Parsons buys Main

BOSTON—The Parsons Corporation, fourth largest engineering-construction firm in the country, has entered into an agreement to acquire C.T. Main Corporation. C.T. Main Corp., ninth largest engineer-constructor, is headquartered here, while Parsons' headquarters are located in Pasadena, CA.

Announcement of the agreement was made by C.T. Main Corporation president Paul Gorman.

1986 budget request . . . from page 1

million, down from $178 this year and $530 million in '82.

● Fusion R&D is slated for $390 million next year, down from $437 million this year, but up from the $317 million planned for 1982—one of the few energy R&D areas to show a gain from the Carter era.

Spending on nuclear waste disposal activities is scheduled to increase to $1.6 billion from $1.3 billion this year. This area has increased substantially since the Carter years but part of the boost is due to fees collected from nuclear utilities under the 1982 Nuclear Waste Policy Act. The fee-supported portion of the 1986 budget is $571 million, up from $327 million this year.

Support for the federal power marketing administrations such as Bonneville is also declining. The 1986 total is $579 million, down from $667 million this year.

The federal energy picture

Two other recent publications from the Department of Energy will, with the 1986 budget proposal, provide a complete picture of the federal energy establishment at the beginning of the second term of the Reagan administration. One is the Secretary of Energy's Annual Report to Congress. It explains the Reagan Administration's rationale for shrinking the federal role in energy and describes the remaining programs in considerable detail.

The other is the Energy Information Administration's Annual Energy Outlook which projects energy trends out to the year 1990 and beyond:

● Total U.S. energy use is projected to increase 11 percent between 1985 and 1990.

● Oil consumption is expected to rise to 17.3 million barrels per day from 15.8 million this year.

● Electricity generation is projected to increase at the rate of 3.3 percent per year over the next five years. (The range is from 2.4 percent to 4.0 percent per year.) Real electricity prices are expected to decline at the rate of 0.2 percent per year.

● Coal output is expected to rise 17 percent by 1990 and 36 percent by 1995 compared to 1985 output.

Kwh sales and GNP . . . from page 1

based on statistical trends from 1947 to 1982 will be 16 percent higher by the year 1995 than a demand forecast based on statistical trends from 1973 to 1982. Both forecasts assume a 3 percent annual growth in GNP.

kWhs CONSUMED PER CONSTANT (1972) DOLLAR GNP	
1976	1.570
1977	1.551
1978	1.533
1979	1.519
1980	1.550
1981	1.518
1982	1.514
1983	1.506
1984	1.473

Source: Energy Information Administration of the Department of Energy

The CRS report states that such a large disparity between the high and low forecasts translates into a differential need for more than 100 additional large power plants at an additional cost of $175 billion.

"It should be noted that neither school of thought is postulating a decline in electricity demand," the CRS report states. "The argument is over how high the rate of increase will be."

CRS researchers note that over most of the 1949-1973 period, for every 1 percent increase in GNP there had been a 2 percent increase in electricity generation. Since 1973, however, the relationship has been close to 1:1.

"Although it is too early to define this shift as a trend, the precipitous nature of the drop over two consecutive periods (1974-1978; 1979-1983) would tend to indicate that some kind of change may be afoot," CRS researchers contend.

Prior to the early 1970s, there was an underlying growth rate resulting from the electrification of the society that was relatively impervious to the fortunes of the national economy, the CRS report notes. With electrification now largely accomplished, electric generation is seen to be more susceptible to swings in the national economy.

The electricity/GNP section of the CRS report concludes by reaffirming the "close relationship" that exists between these two parameters, adding, "The nature of that relationship appears to be evolving, and thus adds to the uncertainty facing the utility forecaster."

Los Alamos report sees shortages

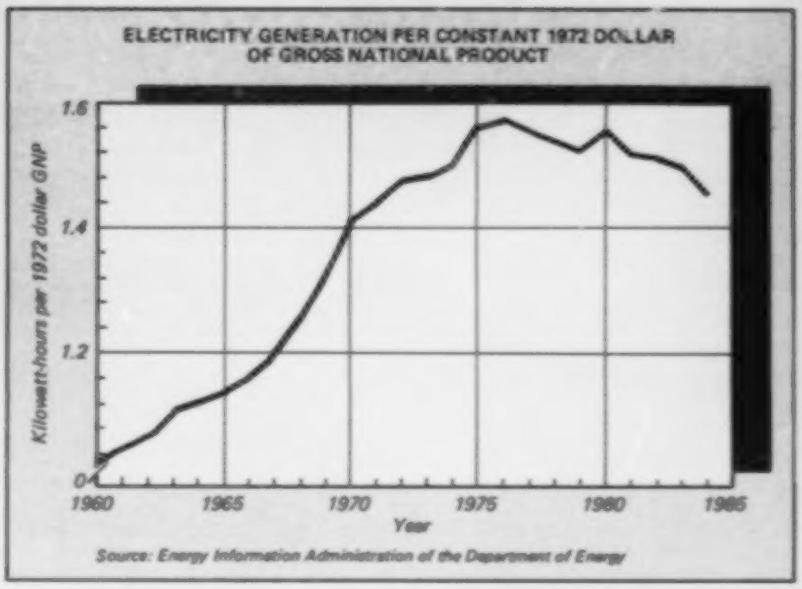
A recent report by the Los Alamos National Laboratory, also noting the "strong positive association" between electricity growth and GNP, concludes that "The future growth rate in electricity demand is uncertain in part because future changes in GNP and the price of electricity are uncertain."

After interviewing 33 electric utilities representing each of the 10 federal regions, Los Alamos researchers were led to conclude that about 300 GW of new electric generating capacity will be ordered and brought on-line in the U.S. by the year 2000. Most of these additions are expected to be added near the end of the century.

Electricity consumption was projected to increase at an annual average rate of 2.9 percent per year.

Such a figure contrasts with the Department of Energy's most recent estimate of a 3.3 percent increase through 1990.

"If the capacity expansion plan of utilities reflect their demand growth projections, and if actual demand growth is consistent with our [Los Alamos] projection . . . future operating capacity may be insufficient to meet demand," states the Los Alamos report, *The Future Market for Electric Generating Capacity: A Summary of Findings.*



ELECTRICITY GENERATION PER CONSTANT 1972 DOLLAR OF GROSS NATIONAL PRODUCT

Source: Energy Information Administration of the Department of Energy

One of the conclusions of the Los Alamos report pertains to the economies of scale in building larger generating plants and the durability of these economies in light of usually longer lead times to construct such plants. The Congressional Research Service has recently concluded that whatever economies of scale are obtained by building larger generating plants are overwhelmed by associated financing difficulties over the longer building time.

Similarly, the Los Alamos team found "There are much stronger tradeoffs between costs and leadtimes than are generally recognized."

In a study in Northern California, Los Alamos researchers found that a utility could pay at most $1,000 per kilowatt for long leadtime (15 year) generic generating units and still meet its financial goals. "The same financial objectives could be met if the plants were available at $4,000 per kilowatt with a five-year leadtime," the researchers discovered.

The analysis was repeated for a coal-dependent utility. Here researchers found that a company could pay at most $650 per kilowatt for long leadtime generic units. If such units were available that could be built in five years, the company could afford to pay as much as $2,750 per kilowatt and still maintain strong financial performance.

In both instances, reductions in the total leadtimes led to acceptable increases in "overnight costs"—those non-time-dependent costs, such as interest or cost escalation. "These results are different from the more conventional engineering-economic cost calculations based on life-cycle costs," the Los Alamos study notes.

The sample of utilities used in the Los Alamos study reflected 40 percent of investor-owned generating capacity and 51 percent of investor-owned nuclear capacity.

B&W honors Duke for Oconee 2 Record

William S. Lee, chairman and chief executive officer, Duke Power Co., (left) receives clock commemorating the world record for continuous operation by a nuclear power plant achieved by the company's Oconee 2 generating unit. Making the presentation was Walter M. Vannoy, president of Babcock & Wilcox, the supplier of the reactor. Although Oconee 2 set the world surpassed the old record of 417 consecutive days of operation on the evening of January 29, it continued to operate toward its goal of 441 consecutive days of operation before being brought down for refueling on February 21, as this issue of *EL&P* was being readied for the press.

KWhs hit new high in January

WASHINGTON, D.C.—Total electric output for the week ending January 26 reached an all-time high, according to statistics compiled by the Edison Electric Institute.

The amount of electricity distributed throughout the continental United States was 54,739 million kilowatt-hours, an increase of 10.4 percent over the comparable week last year.

The previous record was set in 1984 when the net output for the week ending August 11 was 54,095.

EEI says that this is the first time since 1968 that the peak had been set during a winter week.

The Southeast, Mid-Atlantic and New England regions had the largest percentage increases last week with gains of 21.1, 11.1, and 10.3, respectively.

The record output, which will be included in 1985's statistical tabulation of electricity demand and GNP growth, is largely attributable to extreme weather conditions and economic growth, EEI reports.

Electric output for the first four weeks of 1985 is up 2.1 percent over the same period in 1984.

These statistics reflect output of the entire electric utility industry, including both investor-owned and public utility entities.

Total R&D spending will hit $107 billion, says Battelle

COLUMBUS, OH—Research and development spending in the U.S is expected to reach almost $107.3 billion in 1985, according to Battelle Memorial Institute's Columbus Division.

The National Science Foundation reports that $97.0 billion was spent for R&D in 1984.

Battelle said it forecasts a real increase in R&D expenditures of 3.9 percent this year, slightly lower than the ten year average of 4.2 percent.

Industrial R&D funding, projected to increase more significantly than government support, will account for 51.3 percent of the total funding. Battelle said industrial support is expected to be $55.0 billion, up 11.4 percent from 1984.

Battelle said it projects an increase of 10.0 percent in federal support for R&D, with funding expected to be $48.7 billion. Funding by academic institutions in 1985 will be approximately $2.28 billion and other non-profit organizations will provide slightly more than $1.3 billion, according to the institute.

The Department of Energy will account for 9.1 percent of the total federal R&D funding for 1985. Battelle said energy funds will decline for research on alternative energy sources, but not for energy programs in direct support of national defense.

Battelle said that industrial support of research is growing in fields related to electronics.

C8650-4

Volume 63, Number 4
April 1985

09435 1984301 W 3 1962
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CONGRESSIONAL INFO SERVIC D
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Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

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The D. B. Wilson coal-fired generating unit in Ohio County, Kentucky. Alleging repayment default of REA loans, the government wants to foreclose on the plant. The owner, Big Rivers, says REA precipitated the default.

Big Rivers G & T co-op says Justice Department sued with 'unclean hands'

HENDERSON, KY—Big Rivers Electric Corporation has responded to the January U.S. Justice Department foreclosure suit, charging that the federal government "does not come into court with clean hands." Therefore Big Rivers concludes the government is not entitled to relief.

Big Rivers argues that the combination of declining load growth in its territory, a change in federal energy policy, and especially the refusal of the Rural Electrification Administration to live up to its funding agreements, have caused the financial shortfall that put the utility in default of its loan accord.

In January, the Department of Justice filed a civil complaint in U.S. District Court for the Western District of Kentucky charging that Big Rivers was in default on more than $1 billion in loans guaranteed by the REA. The complaint seeks to recover all of its money, focusing primarily on the 440 MW D.B. Wilson-1 coal-fired generating unit that went into service last September. According to acting assistant attorney general Richard K. Willard, this plant and other utility assets are mortgaged to the government. The suit seeks to foreclose on those mortgages.

In a release to the press, the Justice Department noted that the cooperative has been exploring the possibility of merging with the East Kentucky Power Cooperative, Inc. and that it "hoped an economically feasible merger or other satisfactory solutions could be achieved, notwith-

Continued on page 2

Electric utility industry financial status improves

NEW YORK—The earnings of investor-owned electric utilities improved in 1984, with actual earned return on equity averaging an estimated 14.4 percent compared with 14.35 percent in 1983.

According to statistics compiled by the Edison Electric Institute, last year earned returns on equity ranged from 7.1 percent to 20.8 percent.

These and other financial data were reported in mid-February to the New York Society of Security Analysts by EEI president William McCollam, Jr.

On average, electric utilities sought a return on equity of 16.2 percent last year, and were granted an average allowed rate of about 15.2 percent, McCollam said. The 14.4 percent earned return is therefore less than that allowed, which, in turn, is said to be less than the true cost of capital.

There were 80 announced dividend increases last year, compared to a total of 93 in 1983. "Given the construction issues and the financial distress caused by such issues for a number of our companies, it is prudent to anticipate that the dividend policies of the past will be tested during the next few years," McCollam told securities analysts here.

Pre-tax interest coverage of 3.16 was above the 1983 level of 3.06. This parameter ranged from 1.9 to 7.0.

At year end, the market price to book value of utility stock stood at 98 percent on average, McCollam said, compared to 94 percent in 1983. This increase was based on an analysis of

Continued on page 2

Effects of time-of-day rates reported as slight

In a new study, only one in eight investor-owned electric utilities reports any effect on electricity demand from residential time-of-use rates.

In the commercial sector, the result was slightly less than one in seven.

And of 57 investor-owned electric companies reporting to the Electric Power Research Institute (EPRI) that they had implemented T-O-D rates for industrial loads, only 11—just under one in five—said they had measured an impact on class demand.

The EPRI *Innovative Rate Design Survey* of 221 electric utility organizations is said to be the first systematic examination in nearly a decade of how utilities implement and use innovative rate designs.

With responses from 158 utilities, EPRI says the report "is a valuable resource for utilities considering nontraditional pricing programs." Its objective was to document and summarize the types of innovative rate structures now being offered by electric utilities throughout the U.S.

According to the survey, a time-of-use rate is one where one or more of its elements is priced differently for different periods of usage during the day.

While the data show the effects of time-of-use rates on electricity demand to be slight, EPRI researcher John Chamberlin warns against such an unqualified conclusion.

Chamberlin, who was the project manager for the survey, said that the survey questionnaire asked each utility respondent if the implementation of the time-of-use rate had an impact on class load. Thus, he said, many time-of-use rates implemented for small groups of customers—while they may have had a measurable impact on that group's use of electricity—did not affect the overall class of customers.

Also, Chamberlin said that innovative rates often are implemented by utilities under conditions that are less rigorous than those of social experiments so that the effect of the rates on electricity demand can be masked by other factors that influence demand. These include, for example, changes in the number of household residents, greater or lesser family affluence, and the addition of new appliances.

Notwithstanding these cautions, EPRI's Chamberlin notes, "It is fair to say that utilities with residential time-of-day rates are having a hard time saying what the impact is."

For the overall survey EPRI received responses from about 75 percent of the 158 investor-owned utilities contacted and from about 56 percent of the 63 publicly-owned utilities queried. Time-of-day rates were found to be the most widely used of all innovative rate types. Nearly 70 percent of all respondents offered at least one T-O-D rate.

Of the publicly-owned utilities survey by EPRI, eight utilities offered time-of-use rates to residential customers, eight utilities offered such rates to commercial customers, and nine offered them to industrial customers. Impacts were found to be measurable in two cases for each of the utilities offering such rates in that customer class.

Interruptible/curtailable rates are the second most common innovative rate design implemented, EPRI reports. About half the respondents reported offering such a rate, most often to industrial customers. An interruptible/curtailable rate is one where

Continued on page 6

Foreign Power Briefs

- **The Soviet Union** said it will allow the International Atomic Energy Agency (IAEA) to inspect some of its nuclear reactors. *The Wall Street Journal* reported that the chairman of the Soviet Union's Atomic Energy Commission and the director general of the IAEA signed an agreement in February. According to the newspaper, the Soviet Union will not allow inspection of its more advanced reactors. A Soviet statement said the agreement showed Moscow's commitment to arms limitation and disarmament. *The Wall Street Journal* said that while other countries allow IAEA inspections of advanced facilities, Moscow's list included smaller reactors that were technologically outdated.

- **Pakistan** and the United States Agency for International Development have hired Gilbert/Commonwealth International Inc. to conduct a power feasibility study of the Lakhra Coal Mine and Power Generation Project near Jamshoro. Project plans call for construction of a 300 MW coal-fired plant. Gilbert-/Commonwealth said it will determine the type of plant best suited to burn Lakhra lignite grade coal, which has a high moisture and sulfur content. The entire project is expected to cost $815 million.

- **The People's Republic of China** has awarded contracts worth $28 million to General Electric Company for the construction of two MS6001 heavy-duty gas turbines and other turbine parts. GE said one of the gas turbines will be part of a repowering project in Karamay in northwest China, and the other will be used for a cogneration plant in Daqing in northeast China.

- **The Soviet Union** has agreed to help Syria construct its first nuclear power plant. The Syrian Arab News Agency, Sana, reports that Syria's Electric Power Minister announced the accord after returning from a recent visit to Moscow. The Russians have apparently chosen three potential sites for the plant and an agreement has been signed for geological and geophysical surveys.

- **Electricity demand in Canada** rose more than 8 percent last year, according to a survey conducted by the Canadian Electrical Association. Even though demand is up, the CEA said Canada still has surplus energy available for export. In the first nine months of 1984, energy exports increased 9.9 percent from the same period in 1983.

- **Key government, utility and industry officials in India** met with a U.S. delegation of ten renewable energy experts in February to hear how U.S. utilities have used renewable energy for power generation. The group met with officials in New Delhi, Calcutta, Madras and Bombay. Representatives from Southern California Edison, Pacific Gas & Electric, Sacramento Municipal Utility District and Georgia Power Company participated in the trip.

- **More electrical companies** went into liquidation in England and Wales last year than ever before, reports Dun & Bradstreet. A survey showed that 793 electrical firms liquidated last year in the two countries, an increase of 4.9 percent from 1983. Dun & Bradstreet reports that 121 electrical firms declared bankruptcy, up 19.8 percent from the previous year.

- **Japan and China** have agreed to exchange information on nuclear power, fusion, recovery of uranium from seawater and the use of nuclear heat. *Nuclear International Engineering* reports that a Chinese delegation will visit Japan sometime this year.

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The Edison Electric Institute has advanced numerous strategies to revive the nuclear option. But critic Amory Lovins says financial health and energy reliability will be maintained if nuclear plants are abandoned. A point/counterpoint examines the two sides. 16

Seminars to help computer users deal with power quality problems are being sponsored by several utilities.**T/D** 25

Electron-beam irradiation testing at Indianapolis Power & Light Company's E.W. Stout station should get underway sometime this month. The exotic technology removes sulfur and nitrogen oxides simultaneously from flue gases.**G** 33

A SCADA system was upgraded quickly, while on-line, pending installation of a new energy management system.**T/D** 36

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Financial status improves . . . from page 1

100 major electric utility systems.

Rate increases in 1984 showed a decline from the year before. Preliminary data indicate that the investor-owned electric utilities received 184 increases totaling about $4.83 billion, compared to 241 increases totaling $5.373 billion in 1983. These increases, McCollam said, do not include fuel clause adjustments.

As of December 31, 1984, EEI estimates that pending applications for rate relief total about $7.8 billion. The corresponding figure for 1983 was $9.674 billion.

"It is prudent," McCollam said, "to expect that an issue which will dominate many future rate cases will be that of phase-in. As a principle for rate-setting, we at EEI have come out against phase-in which excludes inclusion of CWIP [construction work in progress] in the rate base. But we recognize that local considerations exist which may require the phaseing in of major generating units."

During 1984, the investor-owned electric utility industry spent $28.1 billion on new electric plant, including nuclear fuel. With $6.8 billion added to this figure for allowance for funds used during construction (AFUDC), construction expenditures totaled $34.9 billion.

AFUDC is the calculated return utilities accrue on the funds they have invested in construction projects. The accrual is an accounting measure that becomes actual cash when the construction project becomes operational and goes into rate base.

EEI estimates that companies plan to spend $31.9 billion this year, $28.5 billion in 1986, and $25.1 billion in 1987. These figures include AFUDC and reportedly assume a construction cost escalation rate of about 6 percent.

McCollam said that to accomplish a construction program of this size, some $26 billion—or about 34 percent of the total cash construction requirements—will have to be raised from outside sources over the next three years. On an annual basis, this amounts to $12.0 billion this year, $8.7 billion in 1986, and $5.3 billion in 1987.

"These dropping numbers reflect a declining construction program, coupled with an increasing level of internally-generated funds," McCollam said.

About 35 percent of the total funds needed is expected to be from common equity, including contributions from utility dividend reinvestment plans.

Last year, of the total of $13.9 billion in new money, 62 percent was in long-term debt, 6 percent was in preferred stock, and 32 percent was in common stock. Included in the common stock was $3.5 billion from dividend reinvestment and employee stock ownership plans.

Big Rivers co-op . . . from page 1

standing the filing of this action."

Big Rivers is a generation and transmission co-op, selling wholesale electricity to four member distribution cooperatives in the region. Through these utilities Big Rivers supplies about 71,000 customers with electricity.

In its answer to the Justice Department lawsuit, Big Rivers says that in the late 1970s, in cooperation with REA and in response to load studies, it was granted an REA guarantee to the Federal Financing Bank (FFB) for a $1.1 billion loan to finance the construction of the two-unit Wilson station and associated pollution control and transmission equipment.

However, a revised forecast in 1981 showed a marked decrease in demand. Accordingly, Wilson-2 was deferred.

Big Rivers says it kept the REA informed of all these developments.

Adding to the diminishing load problem, the area's National-Southwire Aluminum Co. in May, 1984 told Big Rivers it would oppose any Wilson-1 unit costs in rates. This was a substantial blow to Big Rivers since the aluminum company's Hancock County smelter reportedly accounts for about 40 percent of the utility's generation.

In light of these developments, Big Rivers says it immediately appealed to REA for relief, redoubling its efforts to sell power from or interests in the Wilson Station.

As part of its petition to REA, Big Rivers says it submitted many financial restructuring proposals to the agency, but all of them were rejected.

On November 16, 1984, Big Rivers (which is subject to Kentucky Public Service Commission jurisdiction) filed for a rate increase of up to 7.8 percent. The petition excluded all Wilson-1 costs. Proceedings are currently in progress.

On November 19, REA cut off all loan funding to Big Rivers, subject, the utility says, to its decision to merge with the East Kentucky Cooperative. The utility said it protested this action, declaring it desperately needed the earlier-committed loan funds to pay contractors.

In an attempt to regain the initiative, Big Rivers on November 28 sued REA Administrator Harold Hunter. The utility sought an order requiring REA to approve FFB drawdowns for the Wilson station. In December, the utility commissioned Bechtel Energy Corporation to conduct a study to determine the feasibility of the East Kentucky merge idea. A final report is expected by mid-June.

"This suit," the co-op argues, ". . . [is] for the actual purpose of forcing Big Rivers to agree without qualification to merge with East Kentucky prior to completion of the Bechtel report, and without regard to what that report shows.

"Since November 19, 1984, the REA Administrator has wrongly refused to certify any drawdowns by Big Rivers of loans from FFB for the completion of Wilson Unit 1," the utility's answer document reads. Big Rivers concedes that beginning on November 23 it failed to make payments on notes it owed totalling more than $27 million, in principal and interest.

But, contends the utility in its answer, "Big River's failure to pay such installments is due entirely to the wrongful refusal of the plaintiff to comply with its loan commitment . . . . The plaintiff cannot rely upon the wrongful act of its agent to place Big Rivers in default on its loan."

Finally, the co-op contends that part of its financial problems can be traced to a "fundamental change" in federal energy policy. This is said to have resulted in the abandonment of four synthetic fuels plants planned for construction and operation in Big Rivers' service territory in the late 1970s and early 1980s, an unanticipated depression in the economy, an unanticipated drop in aluminum prices, and "other factors over which Big Rivers had no control."

Uncertainties erode 'business as usual,' report finds

BARRINGTON, IL—Anyone familiar with the electric utility industry knows that major institutional and attitudinal changes are in the works, and the Congressional Research Service of the Library of Congress, in a new report, has documented the dynamic forces underlying them all.

"The one outstanding problem is the uncertainty that surrounds the electric utility industry," the report states. In language that is every day becoming more familiar, it then adds, "Building [new capacity] to meet the estimated peak under uncertain conditions is the surest way to 'go broke'" (see *EL&P*, January 1985, page 3).

The report, *Gold at the End of the Rainbow?: A Perspective on the Future of the Electric Utility Industry*, is a broad, sweeping, yet tutorial look at the major elements of the industry. These include costs and prices of electricity, the financial situation, and demand and capacity issues. The report is also a call to electric utility executives to make their organizations lean and resilient to change.

Declaring that utility planning should be shifted from traditional "point" forecasting to a series of contingency forecasts, the report notes, "This then means that rather than building to meet an anticipated peak, a utility needs to develop a flexible system able to quickly respond to changing conditions."

Demand, capacity estimates vary

In the light of numerous demand uncertainties that could affect the price of electricity, the CRS calculates that future demand could range from 3,228 billion kilowatt-hours by 1995 to 3,762 billion kilowatt-hours, with growth rates from 2.8 percent to 4.1 percent per year.

"This uncertainty carries over into forecasts of peak load," the report states, and "is accentuated by the difficulty that normally surrounds prediction of the weather and of the relationship between peak and average demand (load factor)."

Drawing on electric supply and demand data released by the North American Electric Reliability Council, the CRS report calculates that for the "low" or "probable" demand cases (see table), no construction beyond what is planned for 1993 is needed. For the "high" demand case, however, about twice as much incremental capacity would be needed as is currently envisioned.

"Thus, in attempting to build to meet an uncertain future peak, the utilities are faced with construction of new plant over the next 12 years that could be as little as 120,000 MW (most of which is already being built), or as much as 230,000 MW," the report reads. The estimated cost of these construction programs ranges between $250 billion [and] $500 billion by 1995.

Although CRS researchers believe that, technically, conservation and load management could be of substantial help in meeting future demand requirements, implementation of these methods as alternatives to generation will not even approach the needed theoretical capability.

Referencing their August 1983 report, *A Perspective on Electric Utility Capacity Planning*, CRS researchers calculate that the effect of conservation from more efficient buildings, equipment, and appliances could produce cost-effective savings of as much as 161,000 MW by 1990 and 214,000 MW by the year 2000. Load management is estimated to save 104,000 MW in 1990 and 124,000 MW by 2000.

"In considering the above contributions," the report declares, "it appears that institutional inertia may prevent full realization of the cost-effective conservation and load management potential. That is, there is a reluctance on the part of people and institutions to make changes or to scrap existing equipment, even if such changes appear to be economically beneficial."

Flexibility the key

According to CRS researchers, achieving a flexible, minimal-risk utility system requires innovation and includes building smaller plants; rehabilitating older ones; beefing up inter-system and inter-regional interties, and moving to create an interregional bulk power market. It also requires developing rate structures to control demand and that permit flexiblity in meeting reliability requirements.

Only smaller generating plants have the advantage of minimizing risk by reducing the utility's financial exposure, CRS researchers say. Confronting the widely-promoted idea that building smaller plants excludes economies of scale inherent in large plants, they note that a review of data for coal-fired plants coming on line between 1978 and 1982 indicates that only plants larger than 1,000 MW show true economies of scale (i.e.,are less expensive).

"Plants below this level do not appear to follow any cost pattern," the researchers note.

In November 1983, CRS conducted a study comparing the economics of building large and small nuclear plants. The report assumed that plants of 400 MW would be 12 percent more expensive than a single 1,200 MW plant; however, bringing these smaller plants on-line sequentially would be less expensive overall. This was because financing difficulties associated with the larger plant would overwhelm the economies of scale the larger plant offered.

"One can conclude that in many circumstances it may be advantageous to forego the economies of scale and build small in order to minimize risk," the CRS researchers conclude in the current report.

Unfortunately for those who might be inclined to respond to these conclusions, a small nuclear plant design has yet to be licensed in the U.S.

On extending plant lifetimes, the CRS team notes that savings can accrue from the fact that the plant already exists, is probably fully depreciated and may not need a new operating permit. Of equal importance is the potential for an increase in plant reliability, lower heat rates, and lower operating and maintenance costs.

"It is apparent that life extension is a procedure that is here," the CRS report states, "and while not necessarily cost effective or possible for every aging plant, it does have the potential to substantially reduce costs."

The CRS report briefly describes some preliminary experiments in the spot-market pricing of electricity and the deregulated sale and purchase of bulk power between certain specified utilities. If these experiments prove successful, and are allowed to proliferate throughout the industry, "the introduction of competition could well change the face of the industry, with attendant changes in the regulatory system," the CRS report suggests. "By the same token, it could result in a more efficient industry, better able to adapt to the realities of the market place over a shorter time period than at present."

SUPPLY AND DEMAND SCENARIOS, 1995

Item	Demand Case			
	Low[1]	Probable[2]	Medium[3]	High[4]
Required Capacity 1995 (million kW)[5]	691.2	716.4	775.2	821.6
Available Supply (million kW)				
Capacity, 1993	698.8	698.8	698.8	698.8
Net Imports[6]	22.8	22.8	22.8	22.8
Total	721.6	721.6	721.6	721.6
Additional Capacity Needed (million kW)	−30.4	−5.2	53.6	110.0
Capital Required (Billion $)[7]				
1993 Capacity	173	173	173	173
Additional Capacity	–	–	84	132
Transmission and Distribution	91	91	132	174
Total	264	264	389	479

[1] 2.7% annual GNP growth, 3.6% annual increase in electric prices, 64% LF.

[2] 3% annual GNP growth, 0.8% annual increase in electric prices, 64% LF.

[3] 3.4% annual GNP growth, 1% annual increase in electric prices, 62% LF.

[4] 4% annual GNP growth, 1.2% annual electric price increase, 62% LF.

[5] Assumes 20% reserve margin.

[6] Converted to equivalent capacity at average capacity factor for Canadian hydro (66.9%).

[7] New coal plants at $1200 per kW, coal conversions at $600, nuclear at $2200, hydro at $1000, other at $600/kW, and transmission and distribution at $750.

Source: CRS and NERC.

Time-of-use rates: benefits murky

Although CRS researchers generally endorse innovation in ratemaking, noting that it can have a substantial effect on operations, they nevertheless conclude that for all their publicity, time-of-use (TOU) rates cannot be shown to accomplish much.

"If rates are to be based on cost, they should follow a time-of-day and seasonal pattern," the report advises. But the CRS researchers are quick to point out that for high load factor utilities, on-peak and off-peak generation costs may be so similar as to make the costs of TOU implementation too high.

"Despite the strong conceptual base for this form of pricing, there are problems, including a need for a timed meter to determine the relationship of the customers' peak to the system peak," the CRS report says.

Given current technology, the installation of such meters is expensive and could impose a substantial financial burden on utilities.

"Whether or not the cost of new and more complex meters would equal the cost of new capacity *not* required is open to argument," the researchers conclude. "The costs and benefits of peak hour pricing are somewhat murky."

Four electric utilities will vie for Edison Medal

WASHINGTON, DC—Four investor-owned utilities will compete for the Edison Electric Institute's highest honor—the Edison Medal. The award will be presented to the winner at the institute's annual convention in Denver on June 12.

The four nominated companies are Baltimore Gas & Electric Company, Duke Power Company, Georgia Power Company and Puget Sound Power & Light Company.

The companies were selected by a committee headed by *EL&P* Editor Robert A. Lincicome, based on information and recommendations provided by top utility executives in all regions of the country. Others on the selection committee were William Hayes, editor of *Electrical World*, and Lucien Smartt, editor of *Public Utilities Fortnightly*.

The nominees have been invited by EEI Chairman Paul D. Ziemer, president of Wisconsin Public Service Corporation, to prepare documentary presentations that will be used by the panel of judges in final selection of a winner.

Baltimore Gas & Electric was selected as a finalist for development of a wide array of programs emphasizing the utility's close identity with the community and demonstrating unusual awareness of human needs and leadership in the pursuit of civic betterment. For example, the company was instrumental in creating the first fund in the nation for assisting needy householders with winter fuel bills. It has been involved in close cooperation with governmental bodies, labor unions and charitable organizations for the relief of suffering, and in educational programs aimed at raising the level of public awareness of feasible conservation measures and accessible sources of assistance in attaining more efficient use of energy. In all, the company's own programs and participating efforts with other organizations has exemplified utility industry effectiveness in dealing with community concerns.

Duke Power Company was nominated for management excellence and courage in constructing and operating its latest nuclear units at levels of construction cost and operating efficiency that conclusively demonstrate that nuclear power remains a safe and economic source of energy, and for its bold program of active political participation as a concerned corporate citizen.

Georgia Power Company's nomination was based on its courage and vision in demonstrating in its day-to-day system operations the very essence of the utility industry's basic philosophy of service by offering customers a computer-based, loadoption program that displays the cost of service in real-time, thereby permitting the customer to select a personal level of demand based on his or her own cost/benefit analysis.

Puget Sound Power & Light Company was nominated for adding new meaning to the term "Corporate Citizenship" through creation and implementation of successful programs to assist needy, elderly low-income customers. These programs reach far beyond those normally offered by electric utilities and include the formation of partnerships of corporations

Continued on page 7

POINT

Rescue nuclear, bolster industry, EEI urges

Group calls for broad reforms to revive nuclear option

Dan Utroska
Associate Editor

WASHINGTON, D.C.—The Edison Electric Institute has put forth a broad strategic outline aimed at reviving the nuclear power plant option in America and rescuing the electric utility industry from potentially dangerous undercapacity.

In a new report, EEI says unanticipated difficulties experienced by investor-owned utilities with power plant financing; with federal, state, and local governments; and with the public acceptance of nuclear power, have practically eliminated the nuclear option in America.

EEI suggests that these problems have seriously eroded the unquestioned authority historically wielded by utility executives in assessing electricity demand and in unilaterally deciding the type, size, and timing of power plants.

Cooperative planning and decision-making is urgently needed, therefore, if the country is not to experience electricity shortfalls.

"What the nation needs now is not more controversy, but a step toward consensus and the development of conclusions that can guide the actions of the federal and state governments and of the [electric utility] industry," reads a newly-issued EEI report.

To this end, the institute calls for the early establishment of a National Commission on Electricity. Composed of a "small and expert group of distinguished Americans," EEI sees the commission taking over the role traditionally occupied by electric utility executives. "It should make judgments on the future growth of electricity demand and the means by which any need can be met by both reductions in demand and increases in supply."

EEI notes that if the commission finds that additional generating capacity will be needed in the future, it should define the circumstances where it "would again become economically rational" for utilities to make major capital investments in new plant. Further, EEI would like the commission to articulate the generating options that it determines are feasible.

Finally, the commission "would recommend policies which flow from its judgments on those issues."

In addition to the formation of such a national commission, EEI also calls for the industry to make greater use of separate nuclear companies and joint ventures to spread nuclear construction risks.

"Even with standardized designs allowing for shortened lead times and lower construction costs, individual utilities may be reluctant to embark on new nuclear construction by themselves."

And in the future, manufacturers and service companies will have to bear more risk than in the past. Future contracts for nuclear construction will have to incorporate "reasonable" cost-increase risks among utilities, suppliers, and architect-engineers, EEI says.

In addition to these recommendations, EEI has proposed a broad agenda of reform, including the licensing of standardized nuclear reactors, the maintenance of safe nuclear operations, and efforts to educate the public about nuclear power.

Nuclear vs industry problems

The Report of the Edison Electric Institute on Nuclear Power goes further than officially suggesting for the first time the end of nuclear power growth in America. It also constitutes the platform from which the national association of investor-owned electric companies voices its concern that the disincentives for new plant construction are virtually universal throughout the industry, existing as much for that portion of the electric utility industry that is financially healthy, as that segment in financial trouble, due primarily to construction difficulties with nuclear power plants.

"Electric utilities are no longer willing or able to embark on major construction projects that threaten them with financial ruin," the EEI report states. "The recent improvement in the financial health of a large part of the electric utility industry should not be confused with a resolution to this problem. The financial improvements are strongly correlated with the completion or winding down of current construction programs. The fact that utilities may be able to gain in financial health when they stop building does not mean that they could remain in financial health with major new construction commitments."

Today, though, those companies currently facing the largest threat of financial ruin are those utilities now constructing nuclear power plants. These financing difficulties, combined with what EEI sees as a host of regulatory, managerial, and public perception problems, has led the institute to formally declare, "A new nuclear unit is now an option no American utility will choose—even when demand growth clearly requires new generating capacity."

Concluding that new post-Three Mile Island regulations have had a large impact on the costs of constructing new nuclear plants, EEI acknowledges what has become increasingly obvious over the past few months—namely, that nuclear plants no longer compete economically with coal-fired power plants.

"The increased costs of the [nuclear] units being completed in the mid-1980s means that most of them will not generate electricity as cheaply as most new coal units equipped with flue gas scrubbers," the EEI report concedes.

But for EEI, such disheartening economics do not necessarily dictate nuclear cancellations. "Even when the nuclear unit is not needed immediately and the more distant costs of completing an alternative generating unit are discounted to allow for the time value of money, the cost of the alternatives will usually be greater than the incremental cost of finishing a substantially completed nuclear unit."

But if current public policy should prohibit the completion of these units, the final death knell for nuclear power in the United States may be struck, EEI says in its report.

According to the institute, the problem with nuclear costs is not only that they have risen precipitously, but that they have risen "unpredictably." This is what has led to industry calls for consensus planning.

In a statement that reveals the present invalidity of nuclear power plant cost estimates, EEI declares, "Under present circumstances, a utility cannot determine the cost of building a unit that complies with all requirements existing at the time and then expect to build that unit."

As devastating to nuclear power as the onerous regulations and unpredictable cost increases of the past, is the growing disinclination of the public—often expressed through local governmental bodies—to approve the operation of nuclear plants. Bringing to mind the current controversy over the Shoreham nuclear plant, where Suffolk County is effectively prohibiting the licensing of the plant by refusing to approve an emergency evacuation plan, EEI states, "While the theoretical possibility that an operating license could be denied to a completed plant has never finally materialized, the risk cannot be ignored."

Referencing the January 1984 rejection by the Nuclear Regulatory Commission's Atomic Safety and Licensing Board of Commonwealth Edison's Byron-1 nuclear license application, EEI concludes that such an action "has made clear that the risk is real."

Byron-1 has subsequently been

Continued on page 18

PLANTS WITH CONSTRUCTION PERMITS AND A UTILITY-SCHEDULED COMPLETION DATE (AS OF FEBRUARY 20, 1985)[1]

Plant	Utility	MWe	Utility estimate of completed construction	Percent completed (December 31, 1984)[2]	Percent completed (December 31, 1980)[2]
1. Diablo Canyon 2	Pacific Gas & Electric Co.	1106	1985	[illegible]	[illegible]
2. Enrico Fermi 2	Detroit Edison Co.	1154	1985	100.0	76
3. Millstone 3	Northeast Nuclear Energy Co.	1150	1985	92.0	36
4. Palo Verde 2	Arizona Public Service Co.	1238	1985	99.6	50.1
5. Perry 1	Cleveland Electric Illum. Co.	1205	1985	97.0	62.8
6. River Bend 1	Gulf States Utilities Co.	940	1985	93.0	23
7. Watts Bar 1	Tennessee Valley Authority	1170	1985	99.0	83
8. Wolf Creek 1	Kansas Gas & Electric Co.	[illegible]	1985	[illegible]	[illegible]
9. Beaver Valley 2	Duquesne Light Co.	923	1986	83.3	41
10. Braidwood 1	Commonwealth Edison Co.	1175	1986	80.0	59
11. Byron 2	Commonwealth Edison Co.	1175	1986	67.0	58
12. Catawba 2	Duke Power Co.	1145	1986	84.1	18
13. Clinton 1	Illinois Power Co.	950	1986	88.7	75
14. Comanche Peak 1	Texas Utilities	1150	1986	99.0	86
15. Hope Creek 1	Public Service Elec. & Gas	1067	1986	94.5	25
16. Nine Mile Point 2	Niagara Mohawk Power Corp.	1100	1986	85.0	38
17. Seabrook 1	Pub. Ser. Co. of New Hampshire	1200	1986	80.0	43.3
18. Shearon Harris 1	Carolina Power & Light Co.	900	1986	90.0	37
19. South Texas 1	Houston Lighting & Power Co.	1250	1986	72.0	58.9
20. Vogtle 1	Georgia Power Co.	1215	1986	73.0	17.6
21. Watts Bar 2	Tennessee Valley Authority	1170	1986	68.0	70
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Commonwealth Edison Co.	1175	1987	54.0	46
[illegible] Peak 2	Texas Utilities Co.	1150	1987	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
26. Perry 2	Cleveland Electric Illum. Co.	1205	1988	44.0	39.5
27. South Texas 2	Houston Lighting & Power Co.	1250	1988	43.0	21.9
28. Vogtle 2	Georgia Power Co.	1215	1988	50.0	4.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
30. Grand Gulf 2	Middle South Energy	1250	1990	33.0	22.4
31. Limerick 2	Philadelphia Electric Co.	1065	1990	31.0	18
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[1] Source: Edison Electric Institute. [2] Source: *Nuclear News*, World List of Nuclear Power Plants.

Point/Counterpoint . . . from page 18

awarded its operating license.

"Until public attitudes become more understanding, it will be difficult for utilities to again consider nuclear units," EEI says in its report.

Finally, EEI admits that its member companies have been part of the problem. "In any assessment of the history of nuclear power, it would be wrong to suggest that the utilities or the architect-engineers and nuclear suppliers have been blameless or that all of the problems of nuclear power arise from deficiencies of law and regulation and the activities of nuclear opponents. Such is not the case. Like any companies launching a complex new technology, the developers of nuclear power have made errors and misjudgments. In some cases they failed to appreciate the complexity of nuclear power and to respond adequately to the demands it poses."

But the institute is not inclined to drop the entire responsibility at the feet of the investor-owned utilities. "But those deficiencies are not adequate to explain why the entire industry has turned away from nuclear power or why even companies confident in their own abilities in construction and nuclear operations will shun nuclear orders."

Acknowledging that predicting future electricity demand is as risky a business as building new nuclear plants, EEI notes that with a peak demand growth of 2.5 percent per year and a capacity margin of 20 percent, additional capacity will be needed by 1992 beyond what is currently being constructed. Somewhere around 1992, the 2.5 percent annual peak demand curve crosses over the installed capacity curve, the latter reflecting plant retirements reported to the North American Reliability Council.

Using what it terms moderate growth rates of GNP and electricity demand, combined with "very modest assumptions" on plant cancellations and retirements, and allowing for achievable incremental reductions in demand, EEI calculates that 100 to 200 GW (gigawatts, or million kilowatts) of new generating capacity will be needed by the year 2000. This capacity, EEI says, is in addition to the units under construction today.

"With the disincentives to building that now face the electric utility industry, that [100 to 200 GW] is a daunting prospect for the industry and a challenge for the nation," the EEI report states. "The danger in the present situation is that decisions not to build that are in the best interest of the individual utilities will not add up to a result consistent with the national interest in adequate generating capacity."

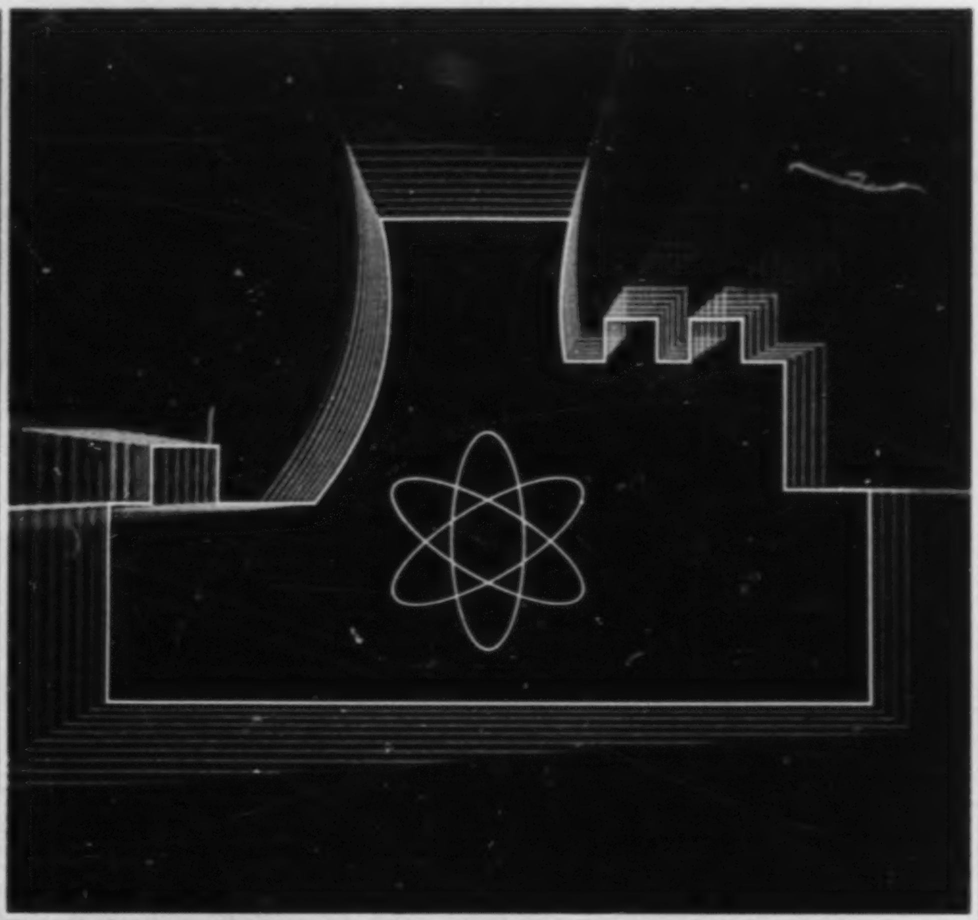
Examination of the accompanying table shows that 31 nuclear plants are currently in the construction pipeline. Unless there are new orders soon, the last six plants will come out sometime between 1988 and 1990, and will mark the end of nuclear power plant additions in the U.S.

Of interest is the fact that all six of these plants due on line between 1988 and 1990, as well as the Braidwood-2 plant which is expected to become operational in 1987, are all less than 55 percent complete at the present time.

The cancellation of any of the nuclear plants now in construction will have to be made up if adequate power levels are to be maintained, EEI suggests.

Further, the institute notes that the attention devoted to nuclear power tends to focus on the troubled nuclear plants now under construction while little regard is given to the role that nuclear power could play in America's energy future.

Again linking perceived industry problems with those of nuclear power, EEI concludes, "In our judgment, the United States is on a course that is full of peril. Our country has drifted into a *de facto* electricity policy that it would not deliberately choose. But if we can soon adopt policies shaped by a long-term view of our electricity situation, it is not too late to avert serious damage to our economy."



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New fiber optics communications system supplier

PITTSBURGH—A joint venture has been formed by Alcoa Conductor Products (ACPC) and Fujikura Ltd. of Japan to develop and market advanced power transmission and fiber optics telecommunications technology. To be known as Alcoa Fujikura Ltd., the new supplier will be headquartered in Spartanburg, SC.

Relocate business

ACPC also will relocate its electrical transmission accessories business from Massena, NY to the Spartanburg plant. Fujiukura will be a minority partner in this new subsidiary—Alcoa Conductor Accessories, Inc.

Fiber optic communications offer utilities substantial improvements in efficient data acquisition, supervisory control and load management savings and can be retrofitted to existing systems through use of established rights-of-way.

Total investment in the two new companies is reported to be $15-20 million. The Spartanburg plant will be fully operational be the end of the year.

Goal satisfied

The new venture is said to satisfy Alcoa's goal of advancing into new, high-tech and high-growth fields and Fujikura's desire to expand in international markets.

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Volume 63, Number 6
June 1985

09625 1957257 W 4 1965
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Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

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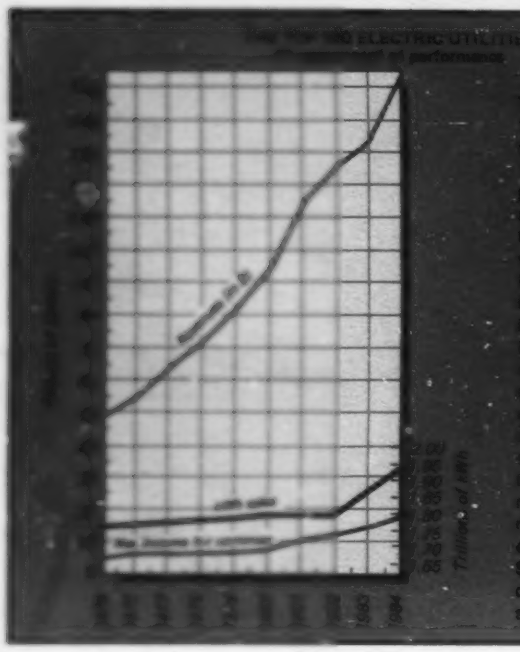

The 20TH ANNUAL TOP 100 ELECTRIC UTILITIES report, which begins on page 11, shows the continuing improvement in the financial and sales performances of the nation's 100 largest investor-owned electric utilities in 1984. Although total kilowatthour sales increased in 1984, and revenue and net income for common stock increased substantially to record highs, the performance of the Top 100 reflects a moderation in activity from a year ago. At the same time, the quality of earnings and real financial strength of most utilities improved. Revenues for 1984 totalled $152.7-billion and net income rose to $17.7-billion on sales of 1.9-trillion kWh.

Industry disunity over accounting goals threatens utility financial interests

Dan Utroska
Associate Editor

CHICAGO—The electric utility industry's inability to speak with a clear, unified voice on pending revisions to industry accounting practices appears to be weakening the effectiveness of individual utility accounting proposals submitted to the nation's accounting standards board.

"It would be helpful to the [Financial Accounting Standards] Board if the various facets of the industry could get their act together and agree among themselves as to what the ramifications of these new phenomena should be," FASB member Arthur R. Wyatt told a special meeting of securities professionals here.

The "new phenomena" referred to by Wyatt are the often-huge dollar amounts associated with state regulatory decisions refusing full or partial cost recovery for plant investments. These disallowances have caused the Securities and Exchange Commission, the Congress, and the financial press increasingly to declare publicly that many of the conventional methods for reporting utility financial transactions are obsolete. As a result, the FASB now finds itself under mounting pressure to revise utility accounting guidelines and to do it quickly.

An "exposure draft" of the board's revised procedures is expected to be released for comment in early July, with final rules to be in place in time for the 1986 reporting year.

As one indication of the disagreement that exists among utility executives over financial accounting methods, Wyatt reported to luncheon attendees of the Utility and Telecommunications Securities Club of Chicago that views differ widely on when and how a utility should recognize a cost disallowance.

In a public hearing held to receive industry views, one chief financial officer of a West Coast utility reportedly argued that he would write down disallowed costs rather than carry them forward as an asset. His reasoning, Wyatt said, was that because this executive's bankers interpreted the disallowance as a loss, the CFO should do likewise.

"I must say it is a fairly persuasive line of reasoning," Wyatt offered.

Most utility executives, however, put forward the counter-argument, he said; namely, that the loss should not be written off, but carried forward in the expectation that recovery through future revenues will be permitted. This argument relies on the long history of regulatory decision making in the U.S. that demonstrates that utility investments will, in one form or another, be recoverable from ratepayers. Notwithstanding certain changes in the regulatory process, nothing has happened that is so revolutionary as to suggest that this process has broken down, the argument continues. And if there has not been a regulatory revolution, there is no need for revolutionary accounting procedures.

Reporting changes contemplated

No one is sure just what the FASB

Continued on page 3

Seabrook financing OK'd; completion still in doubt

Fitchburg withholds May construction payment

CONCORD, NH—The New Hampshire Public Utilities Commission has conditionally approved a $525 million financing strategy submitted by Public Service Company of New Hampshire for its Seabrook nuclear plant, but circumstances existing at the time of the PUC order, as well as subsequent developments, raise serious questions over whether the plant will ever be completed.

Bankruptcy averted

Concluding that it would drive PSNH into bankruptcy if it did not act, the commission stated in its April order that "the public interest would be better served by completing Seabrook than by abandoning the project."

"Substantial evidence affirms our conclusion that a denial of the proposed financing and cancellation of Seabrook unit one without recovery of the investment of $1.28 billion will compel a Chapter 11 reorganization," the order further stated.

A key determinant in the PUC's finding appears to be its reading of New Hampshire state law that prevents recovery of sunk investments in cancelled plant.

Seabrook estimate: $4.65 billion

The combined owners of Seabrook now have $3.2 billion invested in the plant. PSNH currently estimates that unit 1 will cost about $4.65 billion when completed, a figure that includes allowance for funds used during construction. The company projects commercial operation in the last quarter of 1986. This projection was based on full-spending authorization by April 1, 1985.

Although such authorization was not achieved by April 1, a New Hampshire Yankee spokesman said there has been no revision in the total estimated cost of the project. Currently, construction is being conducted at a rate of $8 million per week, even though the joint owners are funding the project at only $5 million per week, or at about two-thirds of the optimum rate. According to NHY's John Kyte, the difference is being made up from earlier construction that came in under budget.

Continued on page 9

Another task-force review of nuclear power promised

DOE's second annual nuclear revival speech given May 8

Dan Utroska
Associate Editor

WASHINGTON, D.C.—Amid both praises and criticisms of the nuclear industry, Department of Energy Secretary John S. Herrington announced on May 8 that the federal government will conduct a comprehensive examination of nuclear power in America.

"I have discussed this issue with the President, and he has decided to have a Cabinet-level review of the status of this important power source," the DOE chief told the Nuclear Power Assembly here. "We are prepared to look at the full range of issues."

It was exactly one year ago to the day when Herrington's predecessor Donald Hodel stood before the same assembly and declared, ". . .The Deparment of Energy is taking steps to see to it that safe and economically feasible nuclear plants under construction can be completed as part of our strategy for a balanced and mixed energy supply.

"Perhaps that time has come," Hodel continued, "when we should consider removing the disincentive in ratemaking experienced by those who have the foresight to opt for the lower, long-term costs of nuclear power.

Secretary of Energy John Herrington

Hodel added, "Because the federal government has been part of the problem for many troubled plants, we must also provide part of the solution."

In this year's nuclear revival address, Herrington confronted the often-heard assertion that the govern-

Contnued on page 20

Foreign Power Briefs

- **The mayor of Stockholm** and the chairman of the Stockholm Energy Company have announced that a 131,000-kW, coal-fired plant using two pressurized fluidized bed combustion units will be installed in Stockholm. The ASEA project will involve replacing an oil-fired unit in a cogeneration plant. It also will provide 215,000-kW of steam heating for downtown Stockholm. American Electric Power said it recently submitted an information proposal to the U.S. Department of Energy requesting federal cost-sharing for a similar project at Ohio Power Company's Tidd Plant on the Ohio River.

- **Coal buyers from nineteen European countries** met with officials of the U.S. coal industry in Holland in April to discuss how trans-Atlantic coal trade might be increased. According to the National Coal Association, overseas coal trade last year totalled 60.65 million tons with a value of $3.053 billion. In 1983 the comparable figures were 60.06 million tons and $3.121 billion. NCA said the outlook for U.S. coal exports in 1985 is "uninspiring," with the overseas component expected to be slightly smaller than last year's level. Impeding short-term growth are several factors, said the association, including the strength of the dollar, limited international credit, high consumer stock levels and aggressive competition from other coal suppliers.

- **Quebec's government** announced it plans to sell preferred stock to the public in Hydro-Quebec, the provincially-owned electric utility. The measure was contained in the provincial budget. According to *The Wall Street Journal.*, Finance Minister Yves Duhaime said that the usefulnees of some state-owned companies had declined in recent years. Duhaime said legislation will be introduced in Quebec's national assembly to permit the sale of preferred shares of the utility. He said the government would maintain control of Hydro-Quebec.

- **Nuclear plant capacity** planned outside the U.S. is on the rise, according to the Atomic Industrial Forum's annual international survey. The AIF survey found that 562 commercial reactors were operable, under construction, or planned in 40 countries outside the U.S. at the end of 1984, compared with 541 units in the previous year's survey. Nine new plants were ordered in 1984, while 18 new reactors began operating outside the U.S. last year. AIF said the number of reactors in the planning stage grew from 157 in 1983 to 172 in 1984.

- **The International Atomic Energy Agency** (IAEA) reports that nuclear energy has accounted for 3,500 reactor/years of safe operation around the world since the first reactor began operating in 1954. During that time, IAEA said there has not been a single accident causing "significant harmful effects on the public." Nuclear power now produces about 13 percent of the world's electricity.

- **The People's Republic of China** (PRC) and the United States have agreed to include coal and other fossil energy topics in future scientific and technological exchanges. The agreement was announced in late April at the US-PRC Joint Commission on Cooperation in Science and Technology meeting. The Department of Energy said the two countries can exchange scientists and technical information as well as fuel samples, materials, instruments and components for joint research efforts. The agreement also establishes a mechanism for organizing joint seminars, conferences and other meetings dealing with fossil energy. DOE said the pact will remain in effect for five years and may be extended by mutual agreement.

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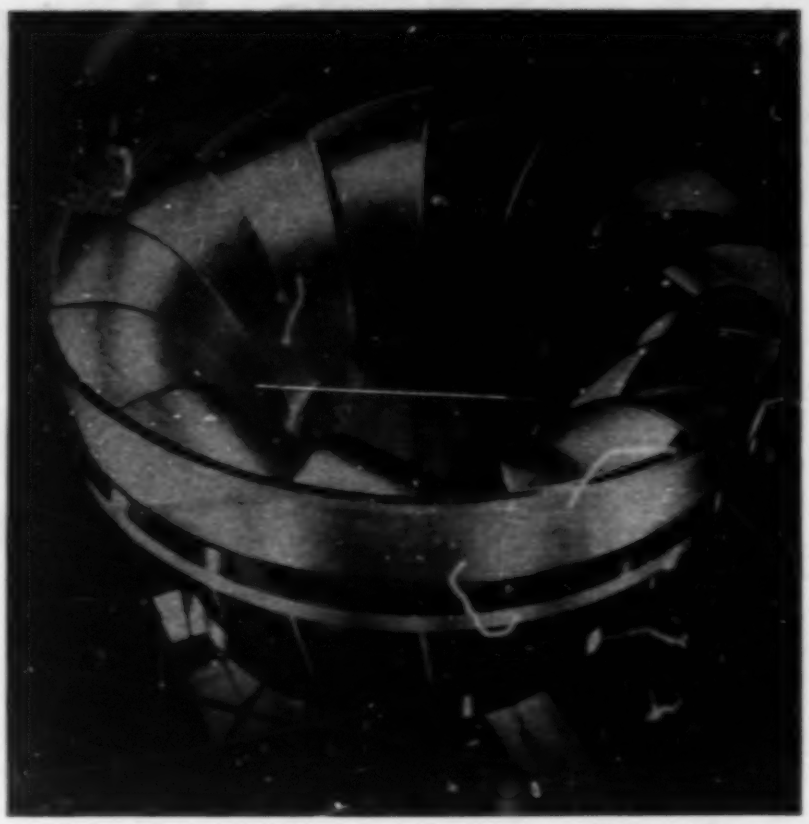
EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Aswan Dam, 180-MW hydro runners shipped as units



One of 12 giant hydro turbines shipped as single units for Aswan High Dam rehab project.

YORK, PA—Allis Chalmers reports that the hydro turbine runners it's building for Egypt's Aswan High Dam are the largest it's ever built and shipped as single units.

The company is rehabilitating the facility's 12 turbines at the rate of two a year. Each turbine will get a new stainless steel runner, shown in the photo.

The runners with 136 tons each, are 22 feet in diameter, and are 12.4 feet high. They operate on a 220-foot head.

The first one was recently hauled via road to Baltimore for shipment to Egypt.

Allis Chalmers said the runners it built for the Grand Coulee Dam in Washington were bigger, but they were built in segments and assembled in the field.

UPC acquires quality assurance lab

ATLANTA—Utility Power Corp. has acquired Universal Testing Laboratories, a 19-year-old Cedar Grove, NJ, organization primarily engaged in supplying inspection personnel for quality assurance functions and related services primarily to the U.S. nuclear industry.

The laboratory since the fall of 1983 has been performing non-destructive testing at U.S. power plants, mainly nuclear.

PASNY T-line structure tested by Meyer

RED WING, MN—A tangent structure to be used on a new transmission line of the Power Authority of the State of New York has been successfully tested to destruction here by its manufacturer, Meyer Industries. The Poly-12 design that was tested is typical of the structures to be used on the 150-mile line to be built between Marcy, near Utica, to East Fishkill, east of Newburgh.

The 142.7-ft steel pole was subjected to 12 loading conditions, including NESC Heavy Wind (104 mph), 1.5-in. radial ice (under single-circuit loading) and continuation of the High Wind test to destruction. The pole failed during the latter test at 115 percent of maximum design loads.

PASNY says it plans to begin construction of the line later this summer. The agency estimates that the line will save consumers an average of $186-million per year by permitting replacement of oil-fueled electricity.

Full-scale tests have been completed on this 142-ft tangent structure for the Power Authority of the State of New York. The tests were carried out by Meyer Industries, fabricator of the pole. This design will be used on PASNY's line from near Utica to East Fishkill, in southeast New York.

20th Annual Top 100 Electric Utilities Report

Most utilities bettered '83 records last year and improved the quality of their earnings

Robert A. Lincicome
EL&P Editor-in-Chief

The improving financial performance of the nation's 100 largest utilities, which began in 1981, continued through 1984, leading to a healthier, more economically viable industry, stronger overall than for many years.

In 1984, total corporate revenue, net income and kilowatt hour sales were up, posting new records, to the surprise of nobody. Earnings per common share grew for the majority of utilities, although the growth tended to moderate after 1983's rapid rise.

In summary, the nation's largest investor-owned utilities sold 1.93-trillion kilowatthours in 1984, an increase of 6.5 percent. These companies produced revenues of almost $153-billion, up 15.7 percent, and net income of more than $17-billion, a 21.2 percent gain. Earnings improved, but only 3 cents per share, the smallest gain in a decade.

But while earnings growth may have slowed, a number of the Top 100 Electric Utilities were able to improve the *quality* of their earnings by reduction of the portion of income represented by Allowances for Funds Used During Construction (AFUDC). This has been done as large-scale construction projects have been completed and cranked into the rate base.

AFUDC is the calculated return utilities accrue on funds used in construction. It represents the cost of money used in capital expansion projects during the construction period, in effect the interest that money could have earned had it been "invested." Until a project goes into service and the cost can be brought into the rate base, AFUDC adds to Net Income, but contributes no cash. Thus, the presence of AFUDC inflates the utility's financial image.

As the ambitious system expansion programs launched in the mid- to late-70s wind down, especially those involving nuclear and other large, long-term projects, utilities have been able to reduce their cash outlays, both from internally generated and external funds. AFUDC has been reduced substantially by many utilities, which has improved the real quality of those utilities' earnings. In fact, as is reported elsewhere in this issue, about a third of the Top 100 electric utilities are in this condition.

Although references in this report are largely to the Top 100 Electric utilities, only 99 companies' performances are included this year. Portland General Electric Company did not provide information despite repeated requests.

Kilowatthour sales for the 99 companies reporting 1984 data increased 6.5 percent in 1984, slightly below the industry's long-term 7-percent growth rate, but healthy compared with other annual post-embargo performances. For example, kWh sales grew only 2.2 percent in 1983 and in 1982 reflected a small decline. The total for 1984, reported by 99 companies, was 1.93-trillion kWh. In 1983, the total posted by those same 99 electric utility companies was 1.829-trillion kWh.

For most utilities, weather tended to be more normal in 1984 than in the past few years, but usage was up in all customer classes. Residential use increased by 3.5 percent, while commercial or small light and power customer use was up 6.0 percent. Industrial and large light and power customer use was up 7.5 percent, reflecting continuation of the nation's economic recovery.

Only 26 companies reported kilowatthour sales increases in excess of the industry's historic 7-percent growth rate. But this represents an almost 100-percent improvement over a year ago. In addition, 87 utilities posted positive gains in kilowatthour sales, a 13 percent improvement from a year ago.

Median change was +4.88 percent, up from 3.22 percent in 1983 and -1.97 percent in 1982.

Among the 10 largest sellers of electricity there were three changes in ranking. Commonwealth Edison, fourth in 1983, fell to sixth, allowing Pacific Gas & Electric and Southern California Edison each to move up a notch, to fourth and fifth, respectively. The rankings of the Top 10 kWh sellers is shown in Table I.

Average annual residential electrical usage reached an all-time high in 1984, topping the previous record established in 1978. Average annual residential use increased to 8823 kWh in 1984, a gain of 1.9 percent from 1983 and 1.4 percent above the 1978 average of 8705 kWh.

As in the past, the utilities reporting the highest residential usages are

EARNINGS GROWTH STATISTICS

Company Name	Rank	% Change From 1983	1984 Earnings Per Share, $
[illegible]	[illegible]	[illegible]	[illegible]
General Public Utilities*	2	[illegible]	[illegible]
Public Service of Colorado	3	[illegible]	2.55
Boston Edison	4	34.72	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Louisville Gas & Electric	6	32.06	3.79
Central Louisiana Electric	7	27.02	3.62
Sierra Pacific Resources*	8	24.12	2.11
Pacific Gas & Electric	9	21.86	2.62
Potomac Electric Power	10	21.43	3.23
[illegible]	[illegible]	[illegible]	[illegible]
Northeast Utilities*	12	[illegible]	[illegible]
Carolina Power & Light	13	18.69	[illegible]
Teco Energy	14	18.47	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Empire District Electric	16	17.93	2.96
Idaho Power	17	16.67	5.25
Southern Indiana Gas & Electric	18	16.36	4.98
Middle South Utilities*	19	16.26	2.86
Public Service Electric & Gas	20	16.18	3.95
[illegible]	[illegible]	[illegible]	[illegible]
Central & South West*	22	[illegible]	[illegible]
Rochester Gas & Electric	23	[illegible]	[illegible]
Iowa Electric Light & Power	24	[illegible]	2.41
[illegible]	[illegible]	[illegible]	[illegible]
Philadelphia Electric	26	12.50	2.70
Central Hudson Gas & Electric	27	12.44	4.43
Baltimore Gas & Electric	28	11.92	5.54
Southern Company*	29	11.11	3.00
Centel*	30	NA	NA
[illegible]	[illegible]	[illegible]	[illegible]
Central Illinois Public Service	32	[illegible]	[illegible]
Long Island Lighting	33	[illegible]	[illegible]
New England Electric*	34	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Wisconsin Public Service	36	9.77	4.27
Wisconsin Electric Power	37	9.57	4.35
Otter Tail Power	38	9.37	3.50
Hawaiian Electric*	39	9.22	2.25
Houston Industries*	40	8.76	3.85
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	42	[illegible]	[illegible]
Kansas City Power & Light	43	[illegible]	[illegible]
[illegible]	44	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Delmarva Power & Light	46	7.35	2.63
Southwestern Public Service	47	7.29	2.65
Union Electric	48	6.77	2.84
Texas Utilities*	49	6.41	4.15
Minnesota Power	50	6.28	4.06
[illegible]	[illegible]	[illegible]	[illegible]
Toledo Edison*	52	[illegible]	[illegible]
Duke Power*	53	[illegible]	[illegible]
Arizona Public Service	54	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Orange & Rockland Utilities	56	4.55	2.76
FPL Group (FP&L)*	57	4.38	2.62
Wisconsin Power & Light	58	3.78	4.12
Northern States Power	59	3.57	5.80
Kansas Power & Light	60	3.00	4.80
[illegible]	[illegible]	[illegible]	[illegible]
Commonwealth Energy System*	62	[illegible]	[illegible]
Niagara Mohawk Power	63	2.53	[illegible]
Kentucky Utilities	64	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Allegheny Power System*	66	1.98	3.61
Pennsylvania Power & Light	67	1.96	3.12
Eastern Utilities Associates*	68	1.79	2.85
Interstate Power	69	1.25	2.43
Ipalco*	70	1.20	4.22
[illegible]	[illegible]	[illegible]	[illegible]
Duquesne Light	72	[illegible]	[illegible]
TNP Enterprises (Tex-NM Power)*	73	[illegible]	[illegible]
Kansas Gas & Electric	74	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Detroit Edison	76	–0.45	2.20
Central Illinois Light	77	–1.64	2.82
Iowa-Illinois Gas & Electric	78	–1.67	4.13
Montana-Dakota Utilities	79	–3.86	3.75
United Illuminating	80	–4.76	5.40
[illegible]	[illegible]	[illegible]	[illegible]
San Diego Gas & Electric	82	[illegible]	[illegible]
Northern Indiana Public Service	83	[illegible]	[illegible]
Savannah Electric & Power	84	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Oklahoma Gas & Electric	86	–7.84	2.47
Atlantic Electric	87	–8.06	3.20
Public Service of New Mexico	88	–11.90	3.11
Public Service of New Hampshire	89	–11.96	3.07
Cincinnati Gas & Electric	90	–16.67	2.45
[illegible]	[illegible]	[illegible]	[illegible]
Midwest Energy*	92	[illegible]	[illegible]
Central Maine Power	93	[illegible]	[illegible]
Puget Sound Power & Light	94	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Utah Power & Light	96	–25.52	1.78
Montana Power*	97	–51.42	2.06
Consumers Power	98	–63.46	1.14
Public Service of Indiana	99	–76.23	1.06
Portland General Electric	100	NA	NA

*Denotes holding company.

SALES DATA

Company	1984 Total Sales (KWH)			1984 Sales (KWH) By Type of Customer (% of Sales)				Average Annual Residential Use		Ratio of Long-Term Debt to Net Plant	
	Rank	% Increase	Average Annual Growth 1979 – 1984	Resid.	Comm.	Indus.	Other	1984	1983	1984	1983
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Southern Company*	6	12.23	3.72	22.1	17.6	33.7	26.7	10,437	10,404	47.6	49.7
TNP Enterprises* (Tex-NM Power)	7	12.08	3.48	26.8	19.4	51.6	2.2	10,372	9,757	37.2	41.5
Southern Indiana Gas & Electric	8	11.48	1.13	21.7	17.3	34.2	28.8	10,704	10,874	46.8	46.2
Wisconsin Power & Light	9	11.12	1.41	25.9	14.8	27.2	32.1	8,064	8,193	38.6	39.1
Southwestern Public Service	10	10.45	3.88	14.2	15.3	41.4	29.1	7,630	7,485	40.2	42.3
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Nevada Power	16	8.80	0.83	43.4	2.9	46.6	7.1	13,812	13,445	44.2	42.3
Public Service of New Hampshire	17	8.64	0.34	28.0	12.0	28.1	31.9	7,067	6,944	47.3	44.8
Public Service of Colorado	18	8.63	1.36	29.2	47.5	17.4	5.9	6,268	6,076	37.5	38.7
Houston Industries*	19	8.19	1.09	24.1	18.3	51.4	6.2	12,620	11,759	39.4	38.1
Empire District Electric	20	7.99	2.67	29.2	18.7	23.2	28.8	9,590	9,266	42.0	43.9
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Central Louisiana Electric	26	7.40	–1.19	39.4	18.7	34.0	8.0	11,262	10,836	37.4	36.6
New England Electric*	27	7.23	0.80	34.8	30.2	25.0	10.0	6,323	6,213	54.8	53.6
Niagara Mohawk Power	28	6.78	0.86	24.1	26.3	30.2	19.4	7,104	6,887	45.5	44.4
Kansas City Power & Light	29	6.66	0.10	29.8	40.6	25.8	3.7	8,327	8,774	113.6	88.5
Idaho Power	30	6.61	5.76	22.2	11.1	23.8	42.8	15,342	14,066	43.3	43.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Toledo Edison	36	5.81	–1.50	26.0	18.5	45.6	9.9	8,045	7,900	108.2	95.3
Southern California Edison	37	5.71	0.13	28.9	32.3	30.2	8.6	6,147	5,879	44.9	44.9
Montana Power*	38	5.56	–1.06	23.7	34.2	19.7	22.4	9,053	8,422	45.4	45.5
Pacific Gas & Electric	39	5.54	0.09	32.7	32.6	25.4	9.3	6,557	6,386	78.0	78.8
Delmarva Power & Light	40	5.45	1.03	27.1	25.0	30.9	17.0	8,283	8,109	42.2	43.0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Public Service of Indiana	46	5.13	–0.62	28.0	21.0	34.9	16.1	10,843	10,479	74.3	72.2
Middle South Utilities*	47	5.09	–0.96	30.3	19.8	42.4	7.4	11,307	11,060	51.4	49.1
Savannah Electric & Power	48	5.06	–1.18	41.0	29.8	25.2	3.9	10,357	10,148	47.2	54.3
Wisconsin Public Service	49	5.01	1.44	26.8	23.4	31.1	19.7	7,269	7,219	32.8	34.4
Cincinnati Gas & Electric	50	4.88	1.23	34.6	23.7	31.2	10.4	9,937	9,889	52.6	46.8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Potomac Electric Power	56	4.45	3.09	24.6	42.1	24.0	9.3	9,362	9,246	43.2	46.4
Scana Corp.* (SCE&G)	57	4.37	1.44	31.1	24.9	34.4	9.6	12,061	12,009	40.7	39.3
Carolina Power & Light	58	3.84	1.56	25.7	17.7	33.1	23.5	11,891	11,889	40.6	41.8
Cleveland Electric Illuminating	59	3.82	–2.51	25.7	25.5	46.3	2.5	6,646	6,608	44.6	40.7
Public Service of New Mexico	60	3.47	4.62	20.3	27.0	12.1	40.7	6,022	5,915	46.9	51.0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
United Illuminating	66	2.94	–0.66	34.5	36.3	27.6	1.5	6,293	6,336	51.5	38.5
Contel*	67	2.81	0.20	27.1	26.7	20.8	25.4	6,794	6,851	NA	NA
Public Service Electric & Gas	68	2.69	0.80	26.5	39.4	32.6	1.5	5,543	5,602	41.1	39.5
Interstate Power	69	2.69	0.13	22.9	17.7	52.6	6.8	7,132	7,373	47.4	48.5
Kentucky Utilities	70	2.64	0.95	31.7	20.3	19.1	28.9	10,873	10,724	37.8	41.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Arizona Public Service	76	2.36	2.02	33.2	34.4	19.6	12.8	10,355	10,357	38.8	41.0
Montana-Dakota Utilities	77	2.36	4.16	41.2	23.9	31.1	3.8	7,866	7,900	41.9	42.8
Consolidated Edison	78	2.28	1.59	25.5	59.7	4.1	10.8	3,391	3,427	36.2	37.8
Eastern Utilities Associates*	79	1.98	0.15	33.5	30.9	23.8	11.8	5,694	5,708	53.2	51.5
FPL Group* (FP&L)	80	1.57	3.15	47.9	37.3	7.5	7.3	10,520	10,745	43.1	40.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Pacificorp*	86	0.35	1.31	28.0	21.2	30.2	20.5	12,289	11,709	52.2	53.9
Dayton Power & Light	87	0.23	0.01	36.5	21.7	31.3	10.5	9,786	9,694	49.5	49.3
Central Illinois Public Service	88	–0.06	–0.11	25.8	11.1	39.1	24.0	8,423	8,671	39.8	37.3
Madison Gas & Electric	89	–0.11	–2.18	26.5	47.9	5.1	20.4	6,085	6,388	41.0	39.7
Dominion Resources*	90	–0.21	2.29	35.2	26.0	17.6	21.2	11,181	11,176	48.2	46.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Northern Indiana Public Service	96	–3.21	–1.58	17.2	3.8	73.7	5.3	6,670	7,038	44.4	49.1
Midwest Energy*	97	–3.29	–0.47	36.1	26.1	20.6	11.2	7,116	7,744	4.8	48.8
Otter Tail Power	98	–7.81	4.18	26.4	14.9	36.6	20.1	10,059	9,862	37.6	37.8
Boston Edison	99	–9.20	1.27	24.6	48.8	15.9	10.7	5,551	5,407	40.1	45.6
Portland General Electric	100			Did not provide data after three requests.							

*Denotes holding company.

in the Northwest, where power costs are relatively low, and in the West, South and Southeast, where summers are long and/or where humidity increases the discomfort level. Leaders were: 1) Idaho Power, 151,342 kWh (+9.1 percent); 2) Washington Water Power, 14,854 kWh (+4.9 percent); 3) Puget Sound Power & Light, 14,259 kWh (+2.0 percent); 4) Nevada Power, 13,812 kWh (+2.7 percent); and 5) Gulf States Utilities, 12,901 kWh (+6.6 percent).

Conversely, utilities at the other end of the scale, those reporting the lowest average annual residential usage, tended to be located in areas where rates were high. Companies posting the lowest uses were: 99) Consolidated Edison, 3,391 kWh (-1.1 percent); 98) San Diego Gas & Electric, 5,407 kWh (+0.5 percent); 97) Public Service Electric & Gas, 5,543 kWh (-1.2 percent); 96) Boston Edison, 5,551 kWh (+2.7 percent); and 95) Duquesne Light, 5,768 kWh (0.3 percent).

TABLE I
THE TOP 10 IN KWH SALES

1	1	Southern Company	114,485	12.23
2	2	American Electric Power	112,320	14.30
3	3	Texas Utilities	69,126	10.23
4	5	Pacific Gas & Electric	63,343	5.54
5	6	Southern California Edison	63,310	5.71
6	4	Commonwealth Edison	63,298	3.40
7	7	Houston Industries (HL&P)	59,748	8.19
8	8	Duke Power	54,399	0.46
9	9	Middle South Utilities	52,990	5.09
10	10	FPL Group (FP&L)	49,351	1.57

Revenues up solidly

Total revenues of the Top 100 investor-owned electric companies climbed a solid 15.7 percent in 1984, a marked improvement from a year earlier when the gain was the smallest in more than a decade. Total 1984 revenues, which reflect all revenues, from all sources, received by utilities or their holding company parents were $152.7 billion, solidly ahead of 1983 performance, when the Top 100 utilities posted total revenues of $132.0 billion and a total revenue gain of 7.0 percent. The 1983 improvement was based largely on rate increases since kWh sales were up just a bit more than 2.0 percent.

For 1984, the nation's larger utilities again profitted from the effects of rate increases, but they came on top of stronger sales performances as well.

In the past year a number of new holding companies were formed to operate electric utilities and at the same time allow pursuit of other businesses beyond the regulation of state commissions. Twenty-six companies among the Top 100 now are considered to be holding companies. In all cases, electric utility operation remains the primary business. In some cases, electric utility operation remains the sole business.

Only five utilities reported decreases in total revenues, and three of these also suffered declines in kWh sales from their 1983 levels.

The largest revenue gains were posted by TNP Enterprises [formerly Texas-New Mexico Power] (+75.5 percent) on the strength of both a rate increase and a 12 percent increase in kWh sales; Kansas Power & Light

(+60.5 percent) largely on the strength of first full year results of its Gas Service Co. operation and rate relief granted in mid-1983; and Puget Sound Power & Light (+26.8) on the basis of rate actions and stronger retail sales results. KP&L was the leader in revenue growth a year ago on the strength of its acquisition of Gas Service Co. in the fall of 1983.

Companies at the opposite end of the scale included: Arizona Public Service (-7.4 percent) as a result of disposing of its gas properties and a small kWh sales increase; Central Illinois Public Service (-1.6 percent) as a result of declines in both electric and gas customers, a return to more normal weather during the peak pricing period and stabilization of the area's economy; and Dominion Resources (-0.3 percent), which suffered a slight decrease in revenues as a result of a slight falloff in kWh sales resulting from loss of two wholesale customers.

TABLE II THE TOP 10 TOTAL REVENUES

1	1	Pacific Gas & Electric	$7,830	17.8
2	3	Southern Company	6,124	13.0
3	2	Consolidated Edison	5,729	3.9
4	6	American Electric Power	4,982	13.4
5	4	Commonwealth Edison	4,930	6.4
6	5	Southern California Edison	4,901	9.7
7	7	Public Service Electric & Gas	4,196	5.9
8	10	FPL Group (FP&L)	3,940	17.5
9	9	Texas Utilities	3,882	12.7
10	8	Houston Lighting & Power	3,874	4.3

A total of 48 companies reported revenues in excess of $1-billion for 1984, an increase of six companies from 1982 and 1983. The ten largest revenue producers are shown in Table II and are the same as a year ago, with only minor shifts in rank.

Net income for common up

With revenues up more than 15.0-percent, construction activity and construction financing declining and almost universal efforts to stimulate productivity and control operating expenses, net income available for common stock grew even more rapidly. Net income of the 98 reporting utilities, at $17.6 billion, was 21.2 percent ahead of 1983, when the total for the 100 reporting companies was $14.6 billion.

Significantly, the 21.2 percent gain in the reported 1984 net incomes of the 98 reporting is the second highest in more than a decade and is a continuing testimonial to the cost-control efforts of company managements. Highest rate of income growth was in 1982, when the overall gain was 22.2 percent. This past year, in addition to a high rate of growth, there appears to have been an improvement in the quality of many of the companies' reported net incomes. This resulted from reduced allowances for funds used during construction as large, long-term construction projects were completed or were winding down. AFUDC, while increasing income figures, represents paper profits and is a non-cash contributor to a company's financial position.

Overall, 83 companies reported increases in net income in 1984, 16 companies reported decreases and one company reported the same income in 1984 as a year previous. A year ago,

FINANCIAL STATISTICS

Company	Net Income		Revenue		Sales (KWH)		Int. Cov. Ratio		Earnings Per Share $	Price/Share 1984 (Dollars)		% Change Long-Term Debt
	Rank	% Gain	Rank	% Gain	Rank	% Gain	1984	1983	1984	High	Low	'83-'84
Boston Edison	6	39.6	4	22.9	100	−9.2	1.00	0.78	4.95	35.500	24.875	−0.11
Louisville Gas & Electric	7	38.4	54	6.8	84	0.7	1.88	1.11	2.79	28.500	22.625	−1.51
New York State Electric & Gas	8	38.1	11	13.6	5	17.8	1.23	1.16	3.60	23.000	14.750	19.58
Central Louisiana Electric	9	37.0	30	6.7	27	7.4	1.80	1.66	3.62	22.250	17.625	27.95
Middle South Utilities*	10	34.5	43	9.1	48	6.1	1.11	0.95	2.88	14.750	9.250	16.79
Iowa Electric Light & Power	16	28.9	67	5.3	92	−0.5	1.21	0.92	2.41	18.375	14.750	−6.52
Ohio Edison	17	27.6	46	8.0	13	9.8	0.80	0.73	2.50	14.125	9.375	14.82
Philadelphia Electric	18	27.4	12	14.8	22	6.6	1.82	1.63	2.70	16.000	9.000	11.71
Carolina Power & Light	19	26.5	22	12.6	60	3.8	1.38	1.24	3.81	26.125	19.250	11.38
Teco Energy	20	24.8	60	5.9	23	7.6	2.18	1.88	3.72	30.500	24.000	10.76
Central Vermont Public Service	26	22.7	44	8.1	42	5.4	2.62	2.26	3.19	17.250	10.875	10.07
Southern Company*	27	21.9	19	13.0	7	12.2	1.45	1.18	3.00	18.875	14.375	5.78
Toledo Edison	28	20.7	36	9.2	37	5.8	0.86	0.80	3.70	18.875	13.375	12.71
Houston Industries*	29	20.6	71	4.7	30	8.2	1.62	1.37	3.85	22.500	17.625	19.80
El Paso Electric	30	20.6	38	8.8	25	7.6	1.26	.37	2.88	14.500	10.000	32.40
Eastern Utilities Associates*	36	18.5	6	19.5	80	2.0	0.84	0.80	2.65	18.000	12.500	12.67
Union Electric	37	17.2	91	0.8	65	3.4	1.31	1.27	2.84	16.500	12.000	16.70
Kansas Gas & Electric	38	15.7	73	4.5	75	2.5	2.82	3.08	3.07	19.000	12.500	32.80
Baltimore Gas & Electric	39	14.9	60	7.5	44	5.3	1.87	1.65	5.54	40.625	30.000	1.58
Otter Tail Power	40	14.3	65	5.6	99	−7.8	1.42	1.28	3.50	28.375	23.000	−1.60
American Electric Power*	46	13.9	16	13.4	6	14.3	0.97	0.87	2.65	21.375	15.125	−2.43
Hawaiian Electric*	47	13.8	48	7.7	74	2.6	1.21	1.10	2.25	21.250	15.340	2.38
Public Service of New Mexico	48	13.5	23	12.0	61	3.5	0.87	0.88	3.11	26.625	19.500	2.82
Illinois Power	49	13.4	94	0.2	57	4.4	2.04	2.23	4.02	23.875	17.625	16.30
FPL Group* (FP&L)	50	13.3	9	17.5	81	1.6	0.98	0.89	2.62	22.875	17.625	11.80
Missouri Public Service	56	11.4	90	0.9	72	2.6	1.49	1.29	3.11	19.750	15.250	−3.26
Wisconsin Electric Power	57	11.0	89	1.2	62	4.7	2.60	2.04	4.36	33.625	25.750	−6.86
Minnesota Power	58	10.9	27	11.6	4	19.4	1.52	1.44	4.06	30.000	23.750	13.24
Madison Gas & Electric	59	10.8	83	2.7	98	−0.1	1.67	1.46	2.86	22.875	18.750	8.17
Wisconsin Public Service	60	10.7	86	2.3	50	5.0	2.48	1.98	4.27	32.875	24.250	−5.23
Duke Power	66	8.4	25	12.0	86	0.5	1.60	1.60	3.96	30.125	22.250	−0.34
Consolidated Edison	67	8.3	76	3.9	79	2.3	3.24	3.01	4.40	31.250	22.625	−1.80
Orange & Rockland Utilities	68	8.2	87	2.3	16	8.9	1.59	1.40	2.76	26.375	19.250	0.00
Wisconsin Power & Light	69	7.9	82	3.6	10	11.1	2.28	2.13	4.12	30.875	25.625	4.51
Pennsylvania Power & Light	70	7.9	3	25.2	35	6.2	1.01	1.18	3.12	25.625	19.500	9.10
Northern States Power	76	5.0	72	4.7	83	1.2	2.23	2.00	5.80	44.250	33.625	5.18
Interstate Power	77	4.4	53	7.0	70	2.7	1.25	1.29	2.43	19.375	15.875	−0.09
Allegheny Power System*	78	3.9	95	−0.2	76	2.5	1.41	1.42	3.61	30.000	24.625	3.33
Northern Indiana Public Service	79	2.4	85	3.3	97	−3.2	0.80	0.80	1.62	16.125	11.125	−4.75
Iowa-Illinois Gas & Electric	80	2.3	78	10.7	93	−0.4	1.39	1.29	4.13	28.625	21.500	−0.18
Iowa Resources*	86	−3.6	68	5.2	94	−0.9	1.46	1.77	4.12	30.375	25.000	0.00
Oklahoma Gas & Electric	87	−4.2	64	5.8	96	−2.0	1.78	2.01	2.47	23.500	19.125	−2.01
Atlantic Electric	88	−4.5	57	6.3	62	3.5	1.40	1.59	3.20	25.000	19.875	1.59
Central Maine Power	89	−10.2	20	13.0	38	7.6	0.72	0.87	1.80	14.750	8.750	27.53
Kentucky Utilities	90	−11.7	78	3.6	71	2.6	1.24	1.34	3.03	25.000	20.375	−6.72
Consumers Power	96	−59.8	37	8.6	55	4.5	0.24	0.64	1.14	16.125	4.125	4.41
Puget Sound Power & Light	97	−71.3	2	26.8	53	4.8	0.21	0.83	1.82	15.000	9.250	5.08
Public Service of Indiana	98	−74.9	74	4.2	47	9.1	0.31	1.50	1.08	13.250	6.875	0.00
Centel*	99	11.1	89	NA	69	2.8	NA	NA	NA	NA	NA	NA
Portland General Electric	100	Did not provide data after three requests.										

*Denotes holding company.

ALPHABETICAL LISTING OF COMPANY PERFORMANCES

	Electric Sales		Customers Served				Revenues			
			Electric		Gas					Net Income
Company	Rank	KWH Sales (millions)	Total (1000's)	% Gain	Total (1000's)	% Gain	Total $ (1000's)	% Electric	% Gas	After Tax $ (1000's)
Boston Edison	49	11,739	596,797	1.3	0	NA	1,316,668	94.7	0.0	74,811
Carolina Power & Light	18	32,072	821,869	3.3	0	NA	1,854,250	100.0	0.0	246,174
Centel*	94	2,831	134,339	0.4	0	NA	180,115	99.2	0.0	NA
Central & South West*	11	48,009	1,493,700	2.6	0	NA	2,786,156	98.2	1.8	317,222
Central Hudson Gas & Electric	77	5,460	225,305	3.0	48,629	2.1	523,189	86.9	13.1	44,678
Cincinnati Gas & Electric	40	15,682	614,335	1.2	367,647	0.4	1,419,179	63.6	36.4	104,382
Cleveland Electric Illuminating	37	17,273	714,768	0.3	0	NA	1,215,353	98.8	0.0	248,279
Commonwealth Edison	6	63,296	3,010,951	0.7	0	NA	4,920,671	100.0	0.0	761,162
Commonwealth Energy System*	76	6,110	296,000	3.1	205,000	1.5	708,508	65.8	34.2	31,941
Consolidated Edison	17	32,411	2,795,022	0.8	1,020,126	0.2	5,728,831	80.5	13.3	581,295
Duke Power	8	54,399	1,395,710	2.8	0	NA	2,710,015	98.5	0.0	399,545
Duquesne Light	50	11,563	560,298	0.8	0	NA	861,776	99.1	0.0	134,839
Eastern Utilities Associates*	90	3,600	235,000	0.9	0	NA	361,325	100.0	0.0	30,053
El Paso Electric	87	4,036	206,903	4.1	0	NA	329,015	99.6	0.0	94,971
Empire District Electric	93	2,912	105,065	1.9	0	NA	124,395	99.6	0.0	14,700
Houston Industries*	7	59,748	1,312,108	3.0	0	NA	3,674,556	100.0	0.0	355,522
Idaho Power	42	15,433	268,989	1.4	0	NA	427,847	100.0	0.0	86,418
Illinois Power	41	15,465	533,352	0.7	381,710	−0.2	1,280,537	63.3	36.7	235,478
Interstate Power	89	3,852	156,638	−0.1	45,013	.0	318,415	65.8	34.2	21,[illegible]24
Iowa Electric Light & Power	84	4,206	204,712	0.1	133,165	0.4	468,228	63.5	35.0	30,0[illegible]
Kansas Power & Light	61	8,469	286,940	1.3	1,000,718	1.3	1,480,182	34.0	66.0	80,089
Kentucky Utilities	53	10,884	378,199	1.3	0	NA	530,904	99.5	0.0	56,287
Long Island Lighting	45	13,985	935,964	1.3	402,430	0.4	1,973,550	81.4	18.6	340,264
Louisville Gas & Electric	63	8,010	302,061	1.1	233,771	0.3	679,536	64.1	35.5	69,502
Madison Gas & Electric	98	2,047	103,030	1.7	71,886	2.5	219,862	56.8	42.9	17,914
Montana-Dakota Utilities	99	1,855	113,751	−0.1	178,802	0.9	357,242	32.2	67.8	30,921
Nevada Power	73	6,187	224,632	4.8	0	NA	318,102	100.0	0.0	38,628
New England Electric*	36	18,256	1,122,930	1.9	0	NA	1,485,727	98.2	0.0	151,601
New York State Electric & Gas	44	14,445	692,811	1.4	130,928	0.4	1,129,086	81.6	18.4	184,006
Niagara Mohawk Power	14	37,086	1,405,000	0.9	436,000	0.7	2,785,546	76.6	23.4	308,274
Orange & Rockland Utilities	86	4,134	219,026	1.9	93,265	1.4	537,985	73.4	26.1	34,431
Otter Tail Power	91	3,316	122,001	0.3	0	NA	172,312	100.0	0.0	19,639
Pacific Gas & Electric	4	63,334	3,686,179	2.6	3,020,803	2.4	7,829,703	65.9	34.1	810,576
PacifiCorp*	27	24,430	655,700	0.8	0	NA	1,786,100	56.5	0.0	157,074
Pennsylvania Power & Light	26	24,498	1,039,381	1.3	0	NA	1,562,782	99.6	0.0	225,758
Public Service of Indiana	38	18,561	549,632	0.9	0	NA	910,276	100.0	0.0	56,978
Public Service of New Hampshire	70	6,841	314,332	4.1	0	NA	525,586	97.6	0.0	115,617
Public Service of New Mexico	72	6,317	243,864	4.5	0	NA	445,328	98.6	0.0	93,288
Puget Sound Power & Light	39	15,693	606,633	3.1	0	NA	657,235	100.0	0.0	22,004
Rochester Gas & Electric	69	7,164	302,190	1.6	236,949	1.6	783,856	60.8	37.2	103,618
Southern Company*	1	114,485	2,800,532	2.8	0	NA	6,123,985	99.3	0.0	719,669
Southern Indiana Gas & Electric	81	4,615	106,952	1.4	64,561	1.1	281,967	68.1	31.9	30,563
Southwestern Public Service	43	15,009	347,896	1.7	0	NA	813,767	99.7	0.0	103,882
Teco Energy	51	11,331	383,083	5.0	0	NA	716,600	99.4	0.0	97,600
Texas Utilities*	3	69,126	1,913,791	7.0	0	NA	3,932,235	99.8	0.0	526,041
Utah Power & Light	34	18,582	490,949	2.5	0	NA	968,269	99.8	0.0	94,564
Washington Water Power	56	9,023	236,094	1.3	78,572	1.8	413,310	67.7	31.7	50,381
Wisconsin Electric Power	33	18,612	830,648	1.0	226,009	2.2	1,434,688	76.1	23.1	149,734
Wisconsin Power & Light	80	8,589	314,895	1.2	106,837	1.9	575,478	73.9	25.5	53,552
Wisconsin Public Service	67	7,470	297,638	1.8	157,022	1.7	644,191	62.9	37.1	50,481

*Denotes holding company.

89 companies reported gains while 11 posted declines.

The median net income change was a 13.3 percent gain and was posted by FPL Group, the holding company that grew out of Florida Power & Light. A year earlier, median net income change was 7.9 percent.

EPS up 1%

Average earnings per share inched up slightly in 1984, to $3.27 per share. This represents a gain of just 1 percent from 1983. By way of comparison, the gain in average earnings per share in 1983 was $0.24, or 8.1 percent. In 1983 average EPS were $3.24, in 1982 EPS were $3.00 and in 1981 average EPS were $2.82.

The small increase in per share earnings, in the light of the solid 21.2 percent improvement in net income, reflects the increased sale of common stock during the year.

The 1984 gain is well below the 12-year average. From 1972 through 1983, the total gain in per-share earnings was $0.72, or 2.3 percent per year. However, the large gain in 1983, one-third of the total 12 year increase, skews the average. The fact remains, however, that the per-share performance of most companies was quite unspectacular and is just two-thirds of the average for the 11-year period 1972-1982, after the large 1983 increase is removed.

For 1984, 72 companies reported gains in earnings and 26 utilities reported declines. This performance is off from a year ago, when 82 companies reported increase in EPS.

For the 98 companies reporting EPS, the median earnings growth was 6.41 percent, well below the 1983 median per-share growth of 9.63 percent. Median growth was 10.2 percent in 1982 and 10.4 in 1981.

As is typical in ranking companies on the basis of growth rates, those organizations coming off poor years tend to rise to the top of the list. This was generally true of the Top 100 utilities in 1984 as 9 of the top 25 utilities came from the bottom 25 a year earlier. But whereas those making recoveries normally have been grouped at the top of the list of fastest growing companies, in 1984 they were scattered fairly uniformly through the top 25 rankings. Four in the top 25 were in that same grouping a year earlier and 7 moved up from the second 25.

Conversely, utilities at the bottom of the 1984 EPS growth list tended to be losers or slow growers the previous year. They also tended to be companies with large construction projects that have gone sour or where PUC regulation has tended to be punitive.

TABLE III
THE TOP 10
NET INCOME AVAILABLE FOR COMMON STOCK

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	2	Pacific Gas & Electric	$810.6	29.0
2	1	Commonwealth Edison	761.2	9.6
3	4	Southern Company	719.7	21.9
4	3	Southern California Edison	660.4	6.8
5	5	Consolidated Edison	581.3	8.3
6	6	Texas Utilities	526.0	13.0
7	8	Middle South Utilities	508.4	34.5
8	7	American Electric Power	487.6	13.9
9	10	Public Service Electric & Gas	429.8	29.6
0	11	Philadelphia Electric	409.7	27.4

EEI details utility diversification in new report

WASHINGTON, D.C.—According to a new Edison Electric Institute survey of 120 member utilities, 86 said they were invovled in at least one other business venture.

The EEI business diversification study of investor-owned electric utilities shows that fuel exploration and development ventures are the most popular type of diversification (26 percent of the companies). The least prominent business venture was identified as business services (one company). See accompanying table.

EEI's survey found that 34 different types of diversification exist among the 120 responding electric utilities. The top four categories of ventures, which include fuel exploration and development, real estate, energy conservation services and cogeneration, represent over 50 percent of the total number of utility business ventures.

The responding utilities are involved in a total of 296 business ventures, said EEI. Of that number, 185 are structured as distinct subsidiaries of a parent utility or holding company. EEI said 35 percent, or 103 ventures, were regulated by either state or federal governments, or both.

Typically diversify

According to EEI, electric companies typically diversify either through a holding company, which may have both utility and non-utility subsidiaries, or through the utility operating company directly.

Utilities that organize through a holding company are under the jurisdiction of the Public Utility Holding Company Act (PUHCA) and are regulated by the Securities and Exchange Commission. Directly-owned operating companies are limited in their diversification by state utility statutes and commission policies.

Among the most popular forms of diversification are real estate ventures, energy conservation services, appliance sales and services, consulting services, fuel transportation and district heating.

Utilities also have set up businesses to sell computer software. Consolidated Edison, Florida Progress, Gulf Power, Iowa Public Service, Iowa Resources, Montana Power, Northern States Power and PacifiCorp all have ventures selling software.

(Popular Diversification Activities)

Based on 296 total responses

Venture Type	Percent of Total
1. Fuel Expl. & Develp.	26
2. Real Estate	13
3. Energy Cons. Serv.	8
4. Cogen./Sm.Pwr.Prod.	5
5. Appliance Sales/Serv.	5
6. Proj. Mgt./Consulting	5
7. Fuel Trans./Transload.	5
8. District Heating	3
9. Load Mgt. Controls	3
10. Computer Software Sales	3

Source: Business Diversification Activities of Investor Owned Electric Utilities./EEI

Other ventures

Some of the more unique forms of diversification reported in the survey include advertising sales, agriculture, business services and timber harvesting.

Kansas Gas & Electric said it has set up a business to sell advertising space in the company's monthly electric bill envelopes. The utility said revenue from the operation goes to offset other utility expenses.

Florida Power & Light owns and manages an orange grove as a non-utility business. The state public utilities commission has not permitted the venture in the rate base.

Florida Progress formed a subsidiary of 300 employees called Better Business Systems. The company designs and manufactures business forms, envelopes, letterhead and packaging materials. It also sells computer-related supplies and accessories.

Three utilities answering the survey—American Electric Power, Duke Power and Florida Power—are involved in timber harvesting. AEP said the land management departments of its operating companies harvest timber from land newly cleared for utility use. Crescent Land & Timber Corp. was formed by Duke Power in 1969 to use non-utility land for harvesting and restoration. Florida Power also sells timber from company-owned land.

American Electric Power reported it has 15 ventures, while Public Service Electric & Gas Company (N.J.) said it has 12. Wisconsin Power & Light has 10 business ventures and Alabama Power reports nine.

Northern States Power and Montana Power each have eight ventures, according to the survey.

For additional information on EEI's *Business Diversification Activities of Investor-Owned Electric Utilities*, contact EEI at (202) 828-7582.

MAC survey finds strong interest in cogeneration

SAN DIEGO—A telephone survey taken by Management Analysis Company (MAC) of 83 electric utilities operating fossil-fueled plants shows a strong interest in cogeneration.

MAC said 57 percent of the utilities surveyed would consider operating a cogeneration plant. The survey also revealed that about one-third of the companies have performed an analysis of the impact of cogneration and decided it is a viable alternative fuel source.

For more information, call MAC at (619) 481-3100.

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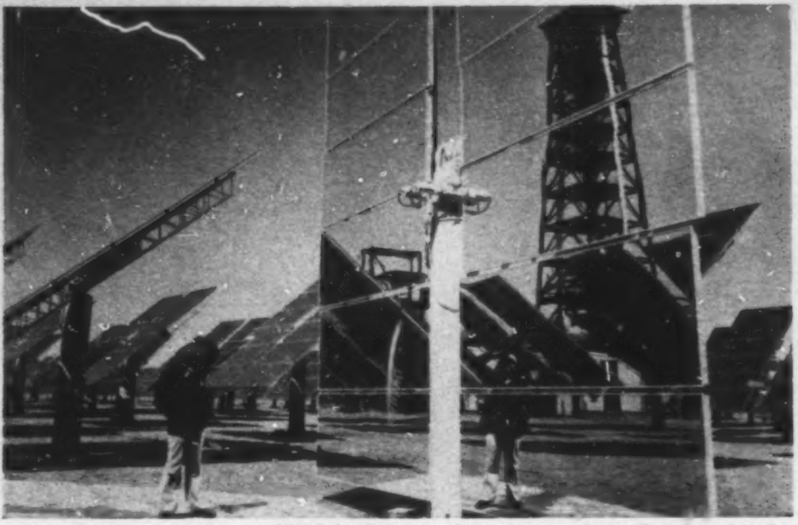
Windfarm operated by Fayette Manufacturing Corp. at Altamount Pass, California has more than 1450 wind turbines.



Heliostats at the pioneering, 10-MW Solar One solar thermal power plant reflect energy to the central boiler.

Can alternate energy live without tax credits?

Robert Smock
Managing Editor

Exotic energy development is at a crossroads.

Solar photovoltaic developers fear the infant industry will not survive loss of federal tax credits coupled with continued "low" oil prices. Several large projects were cancelled recently and two manufacturers dropped out of the business.

Wind energy is growing steadily and economics are improving but development has been limited to three sites in California which account for 95 percent of U.S. wind generation.

Other forms of alternate energy like solar thermal are surviving on federal government research subsidies. Others are limited to remote, unusual applications willing to pay the high costs (the "marijuana farm" market.)

The big breakthrough into large-scale commercial application, either for bulk energy production or decentralized application, has not occurred yet, and some industry observers wonder if it ever will.

Solar photovoltaics

According to consultant Paul Maycock, president of Photovoltaic Energy Systems Inc., Alexandria, Va., the future of the photovoltaic solar industry hinges on the tax credits. If the U.S. investment tax credits die at the end of this year (as scheduled), the world photovoltaic market will be dominated by the Japanese who will get 65 to 70 percent of the market, Maycock predicted. With Japanese domination, the module price will drop to about $2 a watt by 1995 (from today's $5) and the market will grow to about 400 MW, he added.

On the other hand, if U.S. tax credits are extended and expanded, Maycock forecast that U.S. manufacturers will remain dominant with a market share of about 50 percent. Module prices will drop to $2 a watt and the market can grow to a whopping 2000 MW in 1995.

Tax credits are needed because photovoltaic costs are still a factor of 3 to 3.5 away from being competitive economically, Maycock told the recent Energy Technology Conference in Washington, adding that they started at a factor of 30 to 40 away.

At today's PV prices the U.S. market is relatively saturated. Shipments by U.S. manufacturers dropped 10 percent, from 13.1 MW in 1983, to 11.7 MW in 1984, as shown in the table. Maycock attributed 5 MW of the 1984 shipments (and 9 MW in 1983) to tax-credit inspired sales, particularly in California. There, federal and state tax credits and fast write-offs provide an immediate 70 percent return of the installed cost. Maycock said fully half of U.S. manufacturers' 1984 sales were due to tax credit stimulation or government-supported sales.

Although he's a photovoltaic supporter, Maycock said it's not as good an investment as wind or cogeneration for a third-party investor, even though its high-tech reputation continues to lure venture capital. It will be a different story without the tax credits, said the consultant.

"If the tax credits expire we'll all be buying Japanese photovoltaics," warned Maycock. Japanese manufacturers are building on the market they currently dominate for tiny photovoltaic cells in watches, calculators, and other consumer gadgets. There's a big difference between this market and that of the U.S. suppliers. "They started with a market that was profitable," said Maycock.

The consultant claimed that Japanese processing technology is equal to or better than that of U.S. manufacturers and is being improved by an aggressive government development program.

Given rapidly improving technology and the advantage of experience in a competitive marketplace, the Japanese manufacturers have already started to take over the market, as shown in the table—their world market share rose from 23 percent in 1983 to 36 percent in 1984, almost entirely at the expense of U.S. manufacturers.

He noted that Japanese shipments increased 80 percent in 1984. Most of the growth, Maycock reported, was in the new, amorphous silicon technology. Amorphous silicon's market share rose from 14 percent in 1983 to 28 percent in 1984 at the expense of single crystal silicon technology whose market share dropped from 50 to 43 percent.

Maycock added that Japanese multi-kilowatt photovoltaic systems have started to show up in California at competitive costs.

Wind energy developers are also anxious about the federal tax credits,

Continued on page 40

WORLD PV MODULE SHIPMENTS

	1983		1984	
	MW shipped	Percent	MW shipped	Percent
United States	13.1	60.4	11.7	46.8
Japan	5.0	23.0	8.9	35.6
Europe	3.3	15.2	3.6	14.4
Other	0.3	1.4	0.8	3.2
Total	21.7 MW	100%	25.0 MW	100%

U.S. PV MODULE SHIPMENTS BY APPLICATION

Application	1983 MW	1984 MW
Third-party-financed (<5 kW)	4.5	3.0
Third-party-financed central station (1 MW +)	4.5	2.1
Exports	2.0	2.9
Off-the-grid residential	0.8	1.5
U.S. Government projects (SMUD, DOD)	0.7	1.2
Off-the-grid industrial and commercial	0.6	1.0
Total	13.1 MW	11.7 MW

U.S. PV MODULE SHIPMENTS BY COMPANY

	1983		1984	
	MW	Module	MW	Module
Arco Solar	6.0	Single	5.5	Single
United Energy	4.5	Conc.	3.0	Conc.
Solarex	1.3	Poly	2.1	1.5 Poly 0.5 Single[1] 0.1 A-Si
Solar Power	0.4	Single	0.0[2]	
Photowatt	0.3	Single	0.0[2]	
Solec Int'l	0.3	Single	0.4	Single
Solenergy	0.05	Single	0.1	Single
Motorola	0.1	Single	0.3	Poly
Mobil Solar	0.07	Ribbon	0.08	Ribbon
Other (Intersol, Entech, Chronar, Westinghouse, Tideland, Silicon Sensor)	0.05	60% Single 40% Conc.	0.2	20% Ribbon 40% Single 40% Conc.
Total	13.07 MW		11.68 MW	

JAPAN PV MODULE SHIPMENTS BY COMPANY

	1983		1984	
	MW	Module type	MW	Module type
Sanyo	2.0	A-Si	3.5	3.2 A-Si (Consumer) 0.3 A-Si (Terrestrial)
Fuji	0.8	A-Si	2.5	A-Si
Kyocera	0.4	Poly	0.65	0.6 Poly 0.05 A-Si
Sharp	0.8	Single	0.5	Single
ECD/Sharp	0.3	A-Si	0.4	A-Si
Hoxan	0.1	Single	0.3	Poly
Kaneka	–		0.3	A-Si on steel
Nippon Elec.	0.15	Single	0.2	Single
Hitachi	0.07	Single	0.15	Single
Komatsu	0.2	Single	0.1	Single
Mitsubishi	–		0.1	Single
Other (Toshiba, Taiyo Yuden, JSEC, Matsushita, Sumitomo, Mitaka)	0.2		0.2	50% Ribbon 50% A-Si
Total	5.02 MW		8.9 MW	

Source: "Photovoltaic Systems Technology, Cost and Performance to 1995," Paul Maycock, 12th Energy Technology Conference, 1985, Washington, DC.

Exotic energy . . . from page 38

but their technology appears to be closer to commercial competitiveness than photovoltaics.

Paul Gipe of Zond Systems, Inc., Tehachapi, Cal., a major wind machine manufacturer and wind farm operator, told the Energy Technology Conference, "Rapid expansion of the wind industry during 1985 will push the technology further towards commercial generating standards at costs competitive with more expensive conventional fuels. With continued growth the industry will soon reach maturity and wind energy will be competitive with existing energy resources. The industry's growth, however, is threatened by premature expiration of the federal energy tax credits."

Gipe reported substantial progress in wind machine technology since development started in the U.S. in the early 70s. An emphasis on reliability in design in the late 70s and early 80s is now beginning to pay off in improved capacity factors and reduced electricity generation costs. There's been dramatic improvement in capital costs which dropped from $3100 per kW for machines installed in 1981 to $1860 per kW for 1984.

Average machine size increased from about 50 kW in 1981 to between 80 and 100 kW this year.

Gipe said that capacity factors ranged from 5 to 25 percent for California wind machines in 1984 "with selected arrays during 1984 delivering 22 to 23 percent." He claims that 1984 was a poor wind year, so the outlook is good for the future. Annual capacity factor potential is in the 30 to 40 percent range, he claims.

Wind power is concentrated in California, Gipe reported. Wind energy generated in the state in 1984 totaled 195 million kWh (up from 6 million kWh in 1982.) That's 95 percent of the wind energy produced in the U.S. and 75 percent of the world's output, said Gipe.

He added that three firms operate wind farms that account for 58 percent of California's energy output: Zond, U.S. Windpower, and Fayette Mfg. Gipe noted that large corporations have largely abandoned wind power. Only Westinghouse, he claims, is still in the marketplace. He pointed out that the firm recently sold 15 600-kW units in Hawaii.

Unlike photovoltaics, wind power is still growing at a rapid rate. California had 609 MW of wind capacity installed at the end of 1984. Gipe predicted that will rise to 1000 MW by the end of this year.

Gipe repeated Maycock's plea for extension of the federal tax credits. "It's ironic," he told the conference, "that just as the industry nears maturity, growth may be sharply curtailed by expiration of the energy tax credits. Thought the prospect of wind energy improving its competitiveness against entrenched energy sources and becoming more cost-effective is good, there's little doubt that wind energy is at a disadvantage."

He said that wind energy tax credits have cost the U.S. treasury a "paltry" $175 million. Subsidies to other forms of energy development have totaled $162 billion over the past 60 years, he claimed. He added that if the $8 billion still allocated for synfuels were spent on wind energy tax credits it would support 28,000 MW of windpower.

Solar thermal

Speakers from DOE's Sandia National Laboratory brought the Energy Technology Conference up to date on the status of solar thermal technology. Unlike photovoltaics, in which sunlight shining on silicon is converted directly to electricity, solar thermal technology produces electricity by boiling a fluid and using a relatively conventional heat engine.

Solar thermal is still largely supported by government R&D spending. Only a few private ventures have been started.

There are two basic approaches: the central receiver in which a field of reflectors focuses energy at a central heat engine, and the distributed receiver approach in which there are heat-engine/receiver modules or troughs.

Sandia's Alan Skinrood described progress in DOE's central receiver program. The highlight has been the 10-MW Solar One plant connected to Southern California Edison's grid. The plant completed its startup and test phase last August and began a three-year power production phase.

The $120 million facility has exceeded its performance goals, Skinrood reported. It's achieved output levels of 10.4 MW on sunlight steam and 7.3 MW on storage steam. Designed to deliver 28 MWhr from storage (7 MW for four hours) it has achieved 43.4 MWhr from storage. Maximum energy output in one day has been 104 MWhr. Plant availability has averaged 90 percent.

The problem, as with all exotic energy sources, has been cost of electricity from Solar One. Skinrood reported that electricity production costs have been as high as $1.00 per kWhr in some months and as low as 30 cents per kWhr. The long term goal, he said, is 5 to 10 cents per kWh.

A promising development has been a recent drop in heliostat prices. Shown in the photo, the heliostats reflect the sunlight to the central receiver. Skinrood said that a long-term goal of the DOE program has been to reduce heliostat prices to $100 per sq meter. The Solar One heliostats cost $500 a sq meter. ARCO Power Systems Co., which supplied the Solar One units, recently offered to sell heliostats for $200 a sq meter, Skinrood said.

The distributed receiver technology has proven much more popular with private investors with a number of small industrial and commercial installations. Of interest is a 5 MW private project recently started up by LaJet Energy Co. Built near Warner Springs, Cal. the plant has 700 separate solar dishes. The plant has been in a startup phase since last summer, Skinrood reported. He said that the plant was sold to investors for an installed cost of $3600 per kW and he added that it should be able to produce electricity for a cost of 15 cents a kilowatt-hour.

NRC gives TMI-1 a favorable report

MIDDLETOWN, PA—GPU Nuclear received more good news in April after learning the Nuclear Regulatory Commission gave Three Mile Island Unit 1 high ratings in a new assessment of the plant.

GPU Nuclear said it received the highest rating possible in seven of the nine areas evaluated by the NRC. The NRC's Systematic Assessment of Licensee Performance (SALP) covered the period from Feb. 1984 through Jan. 1985.

"In a majority of the areas rated," said the NRC, "licensee management continued to be aggressive in problem resolution and involvement in promoting nuclear safety and radiation protection."

Areas receiving the highest ranking included shutdown plant operations, radiological controls, maintenance, preoperational test and surveillance, fire protection and housekeeping,. emergency preparedness and security and safeguards.

Concerning emergency preparedness, the report said, "The licensee's commitment of substantial resources to the emergency preparedness program in the areas of staffing, training, management, facilities and equipment has provided a superior level of performance."

The NRC's SALP evaluation team recommended that GPU Nuclear meet with the NRC staff to establish priorities on licensing actions not related to restart.

Plant life extension projects announced

CINCINNATI—Cincinnati Gas & Electric announed that it will extend the life of three units at its Beckjord generating station.

Work on unit 3, a 1954 135—MW unit, will be done during a 14-week outage this fall at a cost of $11.5 million. Work on the other two units will be done in 1986 and 1987.

The company said it hoped to add 20 to 30 years to the normal 30- to 40-year life of the generating units.

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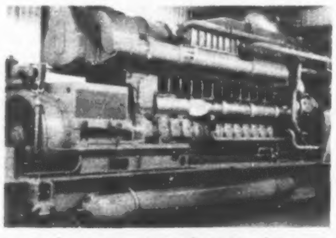

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Volume 63, Number 8
August 1985

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THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY ©TECHNICAL PUBLISHING

Cleveland, Toledo utilities merge to aid N-projects

Dan Utroska
Associate Editor

Spurred by the need to strengthen their access to capital markets in order to complete several nuclear power plants now under construction and to possibly mitigate the impact of large rate increases on Ohio ratepayers, Cleveland Electric Illuminating Co. and Toledo Edison have declared they intend to merge.

Announcement of the proposed $8-billion affiliation came at the signing of a definitive agreement between the two investor-owned electric companies to establish a holding company that will provide overall management, planning, and policy making.

Both Cleveland Electric and Toledo Edison will continue as local companies under their existing boards of directors and management.

The announcement was made June 25 simultaneously in Cleveland by CEI chairman Robert M. Ginn and president Richard A. Miller, and in Toledo by Edison Chairman John P. Williamson. Terms of the agreement call for owners of Toledo Edison stock to receive one share of the new holding company for each TE common share held. CEI owners will receive 1.11 shares of the new holding company for each common share of CEI held. Williamson will act as chairman of the new holding company, which at press time had not yet been given a name. Ginn will be president and chief executive officer, and Miller will be executive vice president.

Regulatory approvals for the merger are seen to be needed from the Securities and Exchange Commission, the Ohio Public Utilities Commission, and the Nuclear Regulatory Commission. If authorizations are expeditiously obtained, the companies expect to have the affiliation finalized by the end of the year.

The new holding company will be among the 20 largest electric utilities in the nation in terms of the market value of its common stock. Individually, CE is 27th largest; TE is 48th. The two companies will have a combined common stock market value of about $2.4 billion and total assets of more than $8 billion.

Nuclear projects are driving force

Together, the two companies own all of the Davis-Besse nuclear plant, operated by Toledo Edison; slightly more than 50 percent of the Perry nuclear plant, unit 1, that is nearing construction completion; and about 44 percent of Beaver Valley 2, being built by Duquesne Light Co. and scheduled for completion near the end of 1987.

At a meeting of New York securities analysts, Robert Ginn was asked why the merger is being proposed at this time. "Obviously," he said, "any companies that are building nuclear plants are having a tough time financing [them]; any companies that are trying to operate nuclear plants are running into problems."

Recalling the companies' ownership of both the Davis-Besse and Perry nuclear projects, Ginn said "that probably is driving the thing to the conclusion" to merge.

The effort to reduce costs was also said to constitute a primary motivation for the merger action.

FACTS AT A GLANCE

	Cleveland Electric	Toledo Edison
Service territory:	1,700 square miles (Ashtabula, Cuyahoga, Geauga, Lake Counties)	2,500 square miles (Defiance, Fulton, Henry, Lucas, Ottawa, Sandusky, Williams and Wood Counties)
Number of customers:	714,768	271,723
residential:	644,904	243,912
commercial:	61,934	23,891
industrial:	7,521	3,920
1984 kilowatthour sales:	17.3 billion	7.5 billion
1984 operating revenues:	$1.2 billion	$551 million
Number of employees:	6,100	2,400
Total plant investment:	$5.1 billion	$1.4 billion
Circuit miles of lines in service:	30,248	8,834
1984 peak load:	3,371 megawatts	1,327 megawatts
Generating plants:	Ashtabula (coal) Avon Lake (coal, oil) Davis-Besse (nuclear) Eastlake (coal, oil) Lake Shore (coal, oil) Mansfield (coal) Seneca (pumped hydro)	Acme (coal, oil) Bay Shore (coal) Davis-Besse (nuc.) Defiance (oil) Mansfield (coal) Richland (oil) Stryker (oil)
First year in business:	1881	1901

LAKE ERIE
Toledo Edison Co.
Cleveland Electric Illuminating Co.
OHIO

According to Linda Caldwell of Duff and Phelps', Toledo Edison clearly stands to benefit from the merger, especially in terms of its ability to complete its financing for the Perry nuclear plant. "Things were getting a little tight for them," Caldwell told *EL&P*. Toledo Edison was one of the relatively weaker partners in the Perry enterprise, from a financing standpoint, but by melding with Cleveland Electric, in the form of the new holding company, it has enhanced its financial stability, Caldwell said.

For its part, Cleveland Electric now has Edison on its side in major construction decisions involving the Perry plant. The holding company owns 51 percent of the project, and while CE will still have to convince other participants in the project that what it wants to do is in their interests, CE and Edison will present a united front to the other partners.

Caldwell said that the financial community has generally reacted positively to the proposed affiliation, and the market also seems to be supporting the action. While Edison stock rose after the announcement of the merger, CE stock remained stable.

Securities ratings confirmed

The day after the merger announcement, Moody's Investors Service confirmed its ratings on the outstanding debt and preferred stock of both companies. The Baa2 ratings of Cleveland Electric's first mortgage bonds and secured pollution control issues were confirmed, as was the Baa3 ratings of the first mortgage bonds and secured pollution control issues of Toledo Edison.

A Baa3 rating is one notch above a non-investment grade security, or "junk bond," as it is commonly called. A Baa2 rating is two notches above

Continued on page 13

Heber testing underway

Construction has been completed and testing is underway at the world's first commercial-size binary geothermal power plant. The $188-million Heber Binary Project, located in California's Imperial Valley, was expected to begin producing electricity in June. San Diego Gas & Electric which manages and operates the project said the plant will eventually produce enough electricity to serve 45,000 people. The project produces electricity from hot underground water using binary energy technology.

EEI issues first expense audit; critics challenge usefulness

Reporting criteria, not EEI response, is major complaint

Dan Utroska
Associate Editor

Disagreement among state regulators and consumer advocates over how the Edison Electric Institute should have been required to conduct its operational audit appears mainly responsible for the sharp criticism the recently-issued document has received.

On July 1, in accordance with an earlier mandate issued by the National Association of Regulatory Utility Commissioners, EEI released its financial operations report. The document follows procedures that were transmitted to EEI by NARUC on how to record and express selected expenses (see *EL&P*, November 1984, page 1).

An operational audit is different from a conventional financial audit in that it seeks to formally trace both the activities and expenditures of each department within EEI.

The time period covered in this first EEI audit report is the last quarter of 1984.

In the audit, operating expenses have been broken down according to eight major categories: legislative advocacy, legislative policy research,

Continued on page 22

Foreign Power Briefs

- **The EEC Commission** will organize a closer information exchange system between its ten member companies, the U.S. and Sweden on 'abnormal events' in nuclear operator reactions. *Nuclear Engineering International* reports that a system is being established so that information on all incidents can be placed in a data bank. All nuclear operator members would have access to the information.

- **Oman's Ministry of Electricity and Water** has been awarded a $7.5-million contract by Power Transmission Lines Ltd., a subsidiary of Dravotec, S.p.A. of Milan, to design, supply and erect a 75-kilometer transmission line. The firm said the 132-kV line will extend from Mabella to Musannah in the Sutanate of Oman and will transmit electricity from the Rusail power plant. The project was expected to get underway in June and be completed in May 1986.

- **Britain's Dept. of Energy** said provisional statistics show that energy consumption in the United Kingdom from January to March rose by 2.9 percent compared with the same period a year ago. Coal consumption fell by 33.2 percent, petroleum use increased 34.4 percent over the same period, natural gas consumption rose by 7.8 percent and nuclear and hydro capacity increased 20.2 percent.

- **Chichibu Cement Company, Ltd.,** Japan's sixth-largest cement producer, has signed a "grant of technology" agreement with Pacific Nuclear Systems Inc. Under the agreement, Pacific Nuclear will distribute Chichibu's polymer impregnated high integrity nuclear waste container in the United States. Pacific Nuclear said NRC approval of the container is pending and expected later in 1985.

- **The China National Technical Import Corporation (CNTIC)** has awarded two contracts to Kaiser Engineers and Constructors, Inc. to assist in development of two coal preparation plants in China. Under the contract, Kaiser said it will provide a computer-controlled system for a coal preparation plant nearing completion in Shanxi province and one for a plant to be built in Anhui province.

- **Germany's ASEA GmbH** has received an order from the German Democratic Republic for eight 200MVA, 220-kV three-phase power transformers. In terms of volume, ASEA said it is one of the biggest contracts in the field to have been awarded in central Europe in recent years.

- **The Egyptian Electricity Authority** has selected Stone & Webster Engineering Corp. to study the feasibility of a proposed 1,200 MW fossil-fired power plant. Stone & Webster said it has been asked to evaluate the need for and timing of the proposed capacity addition, to recommend the number and size of the units required, and to determine whether the plant should be fueled with natural gas, coal or oil. The company said it also will recommend a site and assess the financial and economic feasibility of the project. The study is expected to be completed by October 1985.

- **China's** Ministry of Water Resources and Electric Power said it generated 9.1 percent more electricity in the first six months of 1985 than it did during the same period last year.

- **DOE Secretary John S. Herrington** headed a U.S. delegation in July that attended the International Energy Agency Ministerial Conference in Paris.

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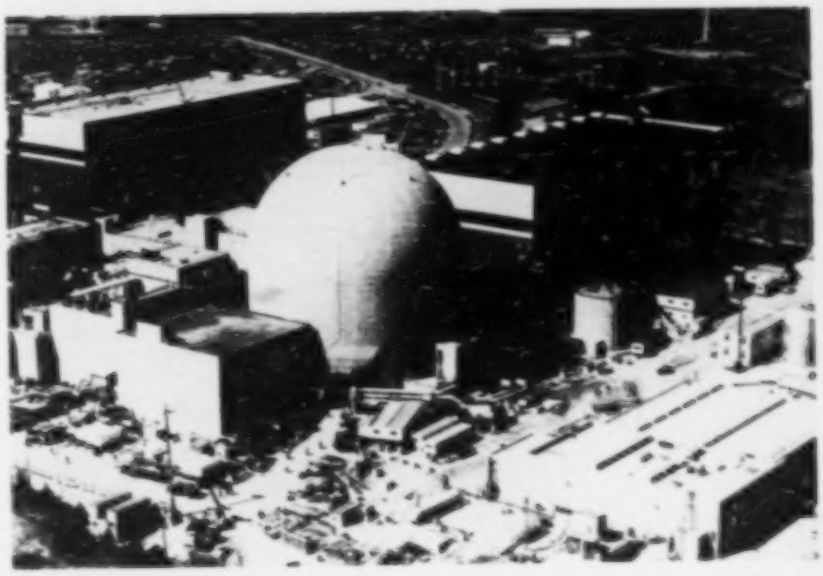
Owners say Seabrook now a 'project under control'



While the Seabrook nuclear plant has had trouble obtaining adequate financing because owners are subject to five regulatory jurisdictions, it now appears that sufficient funding is probable.

SEABROOK, N.H.—Financing needed to complete the beleaguered Seabrook nuclear plant now appears feasible, according to a statement released by New Hampshire Yankee in mid-July. This brightened outlook follows problems last May that threatened to end construction of the project.

As reported by *EL&P* (June, page 1), Fitchburg Gas & Electric announced last May it would withhold its May payment for the Seabrook project and a number of other key utilities were having trouble with their respective public utility commissions in securing authorization to fund the troubled project.

New investors

But according to an annoucement from New Hampshire Yankee, the joint Seabrook owners have found new investors who are willing to negotiate the purchase of the ownership shares of any joint participant that is forced to withhold or stop payments on the project.

Addressing a meeting of the executive committee of the 16 project owners at the Seabrook site, George Edwards, chairman of a task force to resolve financial problems, said that the wiliingness of these potential investors to step in "virtually assures the project's completion."

The new investors are reported to have been identified by Merrill Lynch Capital Markets, which has been acting as investment counselor to the owners' task force.

Edwards said the investors are "very interested in acquiring substantial ownership interests in Seabrook 1 and 2, assuming the price is reasonable and agreement can be reached on terms."

Specific terms of the proposed plan would be negotiated between buyer and seller at the time of the transaction.

Safety net in place

"With this safety net in place," Edwards offered, "the project management team can get on with the job of finishing construction, knowing that adequate funding is available."

Merrill Lynch is also said to be working on interim financing that would be available to any joint owner while that owner engages in negotiations to sell its share of the Seabrook project. As of late June, 84.4 percent of the plant ownership was reported to either have regulatory authorization to finance its share of construction costs to completion, or to have the ability to continue contributing funds to complete the project without further regulatory approval.

Related action

In a related action, five project participants are voluntarily advancing construction payments to prevent a funding shortfall due to non-payment by Fitchburg.

The cash-to-go estimate released in mid-June is $655 million, down from an $830 million estimate made in August 1984. The figures represent the cash still needed to complete Seabrook.

Commenting on the estimate's reduction, Edward A. Brown, president of New Hampshire Yankee said, "This is clear evidence that we have this project under control. It is also good news for consumers that the cost to complete the project is steadily decreasing."

Spending cap lift sought

With arrangements pending to secure all needed financing for the plant, even if some current participants are forced out of the project, Public Service of New Hampshire has petitioned the state Public Utilities Commission to remove the current cap on Seabrook spending.

Currently, PSNH is prohibited from spending more than about $1.8 million per week, which is its ownership share of the approximately $5 million per week currently being expended on construction.

PSNH believes it must increase its weekly spending by about $1.4 million to allow the next major construction milestone, "hot functional testing," to be achieved on schedule.

PSNH president Robert J. Harrison said the company made the PUC petition to avoid construction delays of at least three to four months and additional costs as high as $250 million.

"The completion of Seabrook-1 is now well within sight," he said. "Allowing work to slip now would only push up future costs to consumers and further delay a plant that is needed to maintain an adequate supply of electricity."

Growing business risks challenge utility credit

NEW YORK—Business risks in the electric utility industry are rising, and because of this utility managers and regulators increasingly will have to provide greater financial protection to investors if credit quality and bond ratings are to be maintained.

According to Douglas Randall, senior vice president at Standard & Poor's, the growing riskiness of utility investments are not confined to those companies building nuclear power plants, but apply across the board to all electric utilities.

Speaking here to the annual meeting of the Edison Electric Institute Finance Committee, Randall said that although new plant construction has ebbed in recent years, increased electricity demand and the replacement of old generating capacity is likely to lead to another building boom in the not-to-distant future.

When it comes, he said, it's going to be expensive, especially since the installation of scrubbers on coal-fired power plants is required to handle flue-gas emissions.

"So, while the conclusion of the current construction cycle is providing an opportunity to rebound financially, the next round of construction entails considerable uncertainty as to when it's going to come, what it's going to be for, how much it's going to cost, and, perhaps most important, how you're going to pay for it," Randall said.

"That's risk," he added.

Further, over the past few years, the operating leverage achieved by many utilities has turned sales growth into substantially improved profits. This stems from the fact that as construction winds down and fixed costs are covered, sales revenues send more money to the utility's bottom line.

But this leverage has its dark side, Randall said. When sales decline, profits go down even faster. "As long as incremental costs substantially exceed embedded costs, you'll be flirting not only with the negative impacts of cyclical demand, but also with the possiblity of finding yourself on the elastic portion of your demand curve. That's risk."

In addition, the word out of Washington is that the accelerated cost recovery system and investment tax credits may not survive the tax reform frenzy, at least not in their current form.

"We don't really know what's going to come out of efforts to overhaul the tax code, but we're not optimistic about it," Randall said. "That's risk."

Finally, rising equity levels may not yield appropriate returns and this acts as a disincentive to investors. This possibility leaves the utility with a number of choices, none of them particularly attractive, Randall said. Management can simply accept lower returns for shareholders, thereby reducing the attractivenss of the common stock investments. Alternatively, higher dividends can be paid on stock repurchases. Or management can seek investment opportunities that provide higher returns, although these are likely to be relatively risky ventures. And even if these investment opportunities are successful, there is no assurance these benefits will flow to shareholders.

"It doesn't matter how we look at it, it comes up risk every time," Randall said. "If rising equity levels have to go begging for opportunities to earn equitable utility returns,, that's risk."

Additional risks seen attending utility investments include fuel adjustment clauses that penalize investors if fuel costs exceed certain forecast levels; regulatory prudency reviews; construction cost caps; rate phase-ins; abandoned projects without cost recovery; public officials using utility matters for political gain; diminished load; and the requirement that utilities purchase all non-utility generated power at avoided costs.

Financial 'benchmarks' changed

In response to the growing riskiness of the utility business, in January Standard & Poor's announced that it was making more stringent the criteria it uses in evaluating utility risk factors and determining securities ratings. In general, these new "benchmarks" call for less leverage, stronger earnings, and healthier cash flows than the criteria used previously.

In his speech before EEI's Finance Committee, Randall denied that the S&P change itself made it more difficult for utilities to get and maintain higher ratings.

"We changed the benchmarks to reflect what we see as a meaningfully higher level of business risks in the electric utility industry," he said. "If it turns out that higher ratings are harder to come by—and that may well be the case—it won't be because the benchmarks have been tightened, but because electric utility industry and business risks have gone up without compensating increases in the fundamental financial protection available for securities holders."

Specifically, Randall said that the changed rating criteria include, among other elements, the elimination of allowance for funds used during construction (AFUDC). This move, Randall said, was to more fully key earnings to real cash.

AFUDC is the non-cash, accounting accrual of interest and deferred returns a utility is permitted to tabulate while it constructs a large plant. It is reported as income; only after the plant becomes operational do regulators authorize collection of this statistical fund from ratepayers.

AFUDC, Randall declared, is "an idea who's time has gone."

"These so-called 'earnings' have turned out to be worth even less than the paper they were written on," he said.

AFUDC attacked

Randall attacked the appropriateness of AFUDC on the basis of its recoverability. "S&P used to say that AFUDC was like a long-term receivable," he said. "But, now that phase-ins, imprudency penalties, mismanagment disallowances, and excess capacity denials have become virtually standard operating procedure for regulators, AFUDC looks an awful lot more like a bad debt than a high-quality receivable."

The Standard & Poor's vice president reported that for ratings purposes, AFUDC will simply no longer be employed as a measure of capital productivity, earnings protection, or asset quality. The new ratings criteria reflect this revised perspective.

The new criteria (see tables) also measure cash flow against invested capital, rather than construction spending. This is seen to give a better picture of how rapidly investors can expect recovery of their outlays. The importance of this is emphasized, as construction activity winds down and regulators question whether utilities therefore actually need such healthy cash flows.

Regarding debt leverage, Randall said the S&P criteria are tighter by a couple of hundred basis points across the board (100 basis points equals one percent). But these new benchmarks don't just address capital as reported on financial statements. All off-balance sheet obligations are capitalized, including nuclear fuel leases, capital leases, power purchase contracts, and anything else that might be considered debt. "Dubious" assets are written down or written off.

"When we talk about the need to build equity into the capital structures to reduce leverage and financial risk, it's these adjusted capital structures that we're talking about," Randall concluded.

KEY CREDIT MEASURES – INDUSTRY COMPOSITE

	1970	1975	1980	1984
Pretax coverage** - X	2.85	2.33	2.07	2.52
Cash flow/construction - %	30.0	38.6	29.6	48.9
Cash flow/capital - %	4.0	4.4	3.5	4.8
Debt/capital - %	55.3	52.6	50.4	48.5

**Excluding AFUDC

Source: Standard & Poor's

BENCHMARK RATIOS

	Pretax* interest coverage - X	Cash flow/capital - %	Debt/capital - %
AAA	>4.5	>10	<41
AA	3.5–5.0	7–11	39–46
A	2.5–4.0	5–8	44–52
BBB	1.5–3.0	2½–6	50–58
BB	<2.0	<3	>56

*Excluding AFUDC

Source: Standard & Poor's

Utilities garner top TVB/PUCA gold awards

LAS VEGAS—"Louie the Lightning Bug" came away with top honors at the 7th annual Television Bureau of Advertising/Public Utilities Communicators Association Better Communications Contest here in June.

Alabama Power Company won the Gold Award for utilities with over 500,000 customers for its television commercials featuring the animated character. The commercials are part of the utility's comprehensive youth education program stressing safety around electricity.

For companies with 250,000 to 500,000 customers, the Gold Award went to Portland General Electric Co. for its benefit/value campaign to help customers understand what they get for what they pay.

Sierra Pacific Power Co. won the under 250,000 customer class for its program to improve customers' perceptions of the company as being well-managed, efficient and planning ahead effectively.

Other award winners included Houston Lighting & Power Co., Northern States Power Co., Wisconsin Power & Light Co. and Mississippi Power Company.

Identify with Louie

"One of the primary objectives of the youth education campaign is to tie in with future customers of Alabama Power and provide a positive image," explained F. Neal Wade, Alabama Power manager of public communications. "Kids identifying Louie the Lightning Bug with Alabama Power will have a better feeling about the company fifteen years from now because they learned about electricity from a character called Louie the Lightning Bug."

Eight months after the utility began its advertising campaign, a survey of its service territory showed that 94 percent of the children had heard of the animated lightning bug and 68 percent named Alabama Power as the sponsor.

It works

"If you can bring electric rates down to basically a benefit/value and see what you get for what you pay, it works. Our rate satisfaction level has gone up from 39 percent two-and-a-half years ago to 62 percent," said F.D. Weiden, vice president of public relations and advertising for Portland General Electric.

He added that results are also shown "in a more favorable attitude toward the utility. That went from a 42 percent favorable attitude two-and-a-half years ago to 67 percent, according to independent surveys."

Sierra Pacifc Vice President Stanton K. Berdrow said his company is trying to improve its customers' perceptions.

Through television commercials, the utility tells how Sierra Pacific is meeting its energy needs, what the company has done in the past decade to shift from costly oil and gas to coal-fired generation, and the company's pioneering use of geothermal power.

"In a benchmark study in 1980, only two of ten customers believed we were actively working to solve the rate problem," said Berdrow. "Now, more than six of ten say we're moving forward to take care of the problem. That's the kind of acceptance and understanding you want, but you've got to tell the story. Customers just can't pick it up. You explain and demonstrate it and give them examples. That's what television has let us do."

Labor concession study available free to execs

CHICAGO—A new study by University Research Center which discusses the need to gain wage, work rule and benefit concessions from unions in new contracts is being made available free by the center.

The study cites examples of instances in which such company demands were successfully achieved without labor upheaval.

Single copies of the study, *Does Concession Bargaining Have a Future?*, are available free to executives that request one from Goodfellow at University Research Center, 209 S. Wells, Suite 1830, Chicago, IL 60604.

The Top 100 electric utilities' 1984 operating performances

Robert Smock
Managing Editor

Oil consumption plummeted in 1984...peak demand rose only modestly...new nuclear plants provided a slight boost in generating capacity.

Those are the highlights of this year's annual review of operating data from the 100 largest investor-owned utilities, based on information gleaned from their Uniform Statistical Reports. Data from individual companies are shown on the four large tables on the following pages. Summaries are shown in the smaller tables.

Changes in fossil fuel consumption are shown in Table 1. Coal usage was about the same as in 1983, but oil consumption dropped significantly while gas use rose. That revives a fuel use trend that developed about the time of the Iranian revolution and the subsequent oil price runup in 1979 and 1980.

Utilities with dual-fuel generating capacity switched from oil to natural gas in large numbers. With the cooperation of the federal government, natural gas was made easily available to utilities who could show it would be used to reduce oil consumption.

The trend died out in 1982 and 1983 as rising gas prices and slumping oil prices made gas less attractive. In addition, sluggish electricity demand during the economic recession made it possible to continue reducing oil demand without replacing it with gas. Vigorous growth in electricity demand in 1983 eliminated the oil replacement trend completely, with oil demand actually increasing slightly while gas consumption decreased.

However, utilities seemed to be back on the track in 1984. Natural gas use rose almost 7 percent, the first gain in several years, while oil consumption dipped nearly 17 percent. The top 100 electric utilities burned only 190 million barrels of oil in 1984. Oil consumption by the group peaked in 1978 at 582 million barrels.

While gas consumption was used to offset oil at many utilities, it does not account for the long range decline in oil use by utilities. The top 100's gas consumption was about the same in 1984 as it was in 1978.

Over the long term, coal and nuclear are the generation types that have increased significantly since oil use peaked out in 1978. Coal use by the top 100 grew from 420 miilion tons to 477 million in 1984. Nuclear generation, not shown in the top 100 data, has increased about 18 percent since 1978.

Utilities that showed the largest declines in oil consumption in 1984 (among those that burned at least one million barrels during the year) were:

- Southern Cal. Edison...down 68 percent to 1.1 million barrels,
- San Diego Gas & Electric...down 60 percent to 1.8 million barrels,
- Florida Progress...down 49 percent to 4.7 million barrels,
- Teco Energy...down 44 percent to 1.3 million barrels,
- FP&L Group...down 36 percent to 22.1 million barrels,
- Pennsylvania P & L...down 29 percent to 6.9 million barrels,
- Baltimore Gas & Electric...down 26 percent to 2.3 million barrels,
- Commonwealth Edison...down 23 percent to 4.4 million barrels,
- Consolidated Edison...down 21 percent to 17.6 million barrels,
- Eastern Utilities Assoc...down 20 percent to 2.7 million barrels,
- Orange & Rockland ...down 20 percent to 1.9 million barrels,
- Boston Edison...down 12 percent to 9.1 million barrels,
- Niagara Mohawk...down 11 percent to 6.4 million barrels,
- Dominion Resources...down 8 percent to 2.4 million barrels, and
- Central Hudson G & E...down 6 percent to 6.0 million barrels.

TABLE 1
FOSSIL FUEL CONSUMPTION

	1983	Change	1984	Change
Coal (million tons)	479	+3.9%	477	−0.4%
Oil (million bbl)	228	+0.4%	190	−16.7%
Gas (billion cu ft)	2586	−2.0%	2764	+6.9%

In past years the list of companies that led in reducing oil consumption included several who had converted oil-burning capacity to coal and showed a corresponding increase in coal use. However, that trend seems to have largely run its course—at least for this round of oil price increases.

However, the export of coal-fired energy from Southern Company to Florida is clearly having an impact. All three large Florida investor-owned utilities are at the top of the list of oil consumption reducers. While not strictly conversion to coal, this coal-by-wire does reflect the relative economics of oil and coal.

Gas use up

The short term connection between between oil decreases and gas increases can be seen by looking at the list of utilities with the largest year-to-year gains in gas consumption in 1984 (among those consuming at least one billion cubic feet last year):

- Northeast Utilities...up 142 percent to 5.7 billion cubic feet,
- Philadelphia Electric...up 107 percent to 1.1 billion cubic feet,
- Nevada Power...up 62 percent to 3.2 billion cubic feet,
- Central Hudson Gas & Electric...up 54 percent to 5.1 billion,
- Boston Edison...up 31 percent to 20.0 billion cubic feet,
- Pacific Gas & Electric...up 31 percent to 24.8 billion cubic feet,
- Consolidated Edison...up 30 percent to 87.7 billion cubic feet,
- San Diego Gas & Electric...up 29 percent to 48.4 billion cubic feet,
- Orange & Rockland...up 27 percent to 16.7 billion cubic feet, and
- Delmarva Power & Light...up 27 percent to 2.8 billion cubic feet.

Of the ten utilities with the largest increases in gas use in 1984, six also showed up on the list of utilities with the largest decreases in oil use. California utilities clearly took advantage of gas to reduce oil consumption in 1984. They lead the list of utilities with oil declines and two are on the list of those with the largest increases in gas use.

Coal use was not much changed in 1984. Here's how the largest coal users fared:

- Southern Company...up 12 percent to 39.7 million tons,
- Texas Utilities...up 1 percent to 29.6 million tons,
- American Electric Power...up 2 percent to 15.8 million tons,
- Commonwealth Edison...down 15 percent to 14.3 million tons,
- Detroit Edison...up 4 percent to 14.2 million tons,
- Union Electric...up 4 percent to 11.8 million tons, and
- Carolina Power & Light...up 8 percent to 10.6 million tons.

Southern Company's Florida connection is in evidence.

Efficiency still climbing

The large table showing individual company fuel consumption also ranks the top 100 by system heat rate. Overall, utility thermal efficiency continues to improve. Since 1982 when the median was 10,790 Btu/kWh, the median has dropped to 10,650 in 1983 and 10,616 in 1984.

The most efficient utilities are pretty much the same as in recent years, with a slight shuffling of positions in the top 20.

EL&P has been criticized for publishing this annual heat rate ranking of utilities. "You're not even comparing apples and oranges," said one critic who cornered an editor at the American Power Conference. Differences in geography, fuel types, plant age and type, pollution control equipment, and a host of other factors make comparisons almost meaningless, the critic argued.

It is true that it would be grossly unfair to conclude that a utility ranking higher than another on the heat rate table is better managed...or that a utility whose system heat rate increased is suffering from some blunder in plant operation.

However, *EL&P* plans to continue publishing the data. We deplore the way some may misuse it, but we don't feel that's a good reason for not publishing it.

TABLE 2
PEAK DEMAND AND RESERVE MARGINS

	1983	Change	1984	Change
Seasonal peak (MW)	378,465	+4.2%	383,377	+1.3%
Total system capability (MW)	474,238	+1.6%	476,664	+0.5%
System reserve margin	25.3%		24.3%	
Total owned capability (MW)	443,370	+0.9%	449,432	+1.4%
Owned reserve margin	17.1%		17.2%	
Average load factor	57.7		59.6	

TABLE 3
TYPE OF GENERATION (MW)

Type	1983	Change	1984	Change
Conventional steam and combined cycle	338,646	−0.3%	340,911	+0.7%
Hydro and pumped storage	24,613	−2.1%	24,731	+0.5%
Gas turbines and internal combustion	37,488	+1.5%	34,346	−8.4%
Nuclear	46,604	+8.1%	51,608	+10.7%
Total	447,351	+0.5%	451,596	+0.9%

There are some utilities with systems similar enough to make comparisons meaningful and the heat rate data has spurred some informal competitions over the years that can only benefit everyone involved.

Changes in heat rate or differences in relative rankings can not support conclusions by themselves, but the changes do suggest questions about utility operations that can lead to meaningful conclusions.

As in past years, the 20 most efficient base-loaded generating units

HEAT RATES AND FUEL CONSUMPTION

Company	Rank	Heat Rate (Btu/kWh)	Up or Down	Fuel Consumption: Coal (1000 tons)	Oil (1000 bbl)	Gas (1000 MCF)	Percent Change In: Coal	Oil	Gas
Commonwealth Energy System	1	9,643	D	0	7,222	3,385	0	+31	+23
Consumers Power	2	9,844	D	6,260	330	358	+6	+29	+57
Duke Power	3	9,853	U	9,835	145	184	–19	–11	–56
Dayton Power & Light	4	9,951	D	4,437	8	45	–1	–27	–38
United Illuminating	5	9,956	U	0	8,108	0	0	–4	0
American Electric Power	6	9,957	D	[illegible]	8	0	[illegible]	–	0
Detroit Edison	7	9,980	D	14,210	102	8,000	–4	–13	–29
Cincinnati Gas & Electric	8	9,986	D	7,301	266	86	+3	–60	–34
New England Electric System	9	10,071	D	3,284	7,700	3,701	+16	–3	+20
Florida Progress	10	10,074	D	3,818	4,678	8,865	+1	–40	–14
South Carolina Electric & Gas	11	10,099	U	3,775	1	168	+7	0	–58
Illinois Power	12	10,107	D	7,275	73	371	–2	–57	–35
Potomac Electric Power	13	10,115	D	6,689	3,278	0	+5	+2	0
Public Service of Indiana	14	10,119	D	13,317	1	0	+16	–75	0
Southwestern Public Service	15	10,123	D	5,110	16	72,940	+19	–	–3
Allegheny Power	16	10,136	D	16,788	8	0	+3	–	0
Central Hudson Gas & Electric	17	10,154	U	0	6,800	5,098	0	–6	+64
Toledo Edison	18	10,183	D	3,017	4	91	+12	+33	+23
Carolina Power & Light	19	10,188	D	10,884	15	834	+8	–77	–62
Southern Company	20	10,203	D	30,884	88	4,280	+62	–40	[illegible]
Union Electric	21	10,210	U	11,839	37	497	+4	–56	–27
Boston Edison	22	10,233	U	0	9,126	20,000	0	–12	+31
Houston Industries	23	10,277	U	9,309	46	361,992	+9	–80	+1
Teco Energy	24	10,316	U	5,058	1,334	0	+13	–44	0
Eastern Utilities Associates	25	10,331	U	391	2,743	0	+45	–20	0
Sierra Pacific Power	26	10,331	D	400	8	3,285	+3	–46	–55
Pennsylvania Power & Light	27	10,346	U	11,110	6,804	0	+1	–39	0
Central & South West	28	10,377	D	11,308	157	250,072	–2	–70	+4
Public Service of New Hampshire	29	10,387	D	1,188	3,801	0	+10	+27	0
Orange & Rockland	30	10,401	D	0	1,850	58,346	0	–30	+27
Cleveland Electric Illuminating	31	10,416	D	6,185	74	0	–	–34	0
IPALCO	32	10,461	D	5,209	47	1	–4	–6	–
Hawaiian Electric	33	10,467	U	0	10,734	0	0	+2	0
Central Illinois Light	34	10,471	U	2,146	0	67	–4	0	–34
Long Island Lighting Co.	35	10,483	U	0	15,531	29,149	0	0	–
Niagara Mohawk Power	36	10,486	U	3,289	6,401	37,818	+1	–11	+13
Savannah Electric & Power	37	10,498	D	946	13	473	+7	–82	–86
Central Illinois Public Service	38	10,504	D	5,236	28	0	–4	+142	0
Gulf States Utilities	39	10,505	D	1,760	85	330,307	–4	–67	–1
Midwest Energy	40	10,529	D	1,862	13	380	–1	–30	+60
Atlantic Electric	41	10,535	U	1,195	2,319	1,399	–2	+1	–27
Louisville Gas & Electric	42	10,538	U	3,646	–	888	–2	–	+158
FP&L Group	43	10,545	U	0	22,186	107,923	0	–36	–4
Ohio Edison	44	10,551	D	10,323	21	0	+9	–9	0
Utah Power & Light	45	10,557	D	7,568	3	306	+10	–96	–77
New York State Electric & Gas	46	10,562	U	5,126	21	0	+10	–	0
Delmarva Power & Light	47	10,567	D	2,626	3,224	5,335	–2	–	+27
Dominion Resources	48	10,581	D	8,580	2,388	2,813	+16	–8	–8
Wisconsin Power & Light	49	10,582	U	3,314	49	91	+3	0	–61
Public Service Electric & Gas	50	10,616	D	3,857	6,900	60,636	–7	+13	–3
Southern Indiana Gas & Electric	51	10,626	D	2,094	0	402	+6	–100	+7
Idaho Power	52	10,632	D	2,073	1	5	+29	–	–
General Public Utilities	53	10,644	D	6,928	1,279	26,705	–6	+9	+3
San Diego Gas & Electric	54	10,646	U	0	1,751	48,409	0	–60	+29
Rochester Gas & Electric	55	10,647	D	798	422	296	–4	–34	+75
Baltimore Gas & Electric	56	10,677	D	3,291	2,311	732	+43	–36	–40
Missouri Public Service	57	10,680	U	1,460	8	76	+2	–86	–25
Duquesne Light Co.	58	10,682	U	4,646	78	11	+10	–19	–
Central Louisiana Electric	59	10,711	U	703	1	29,260	+16	–62	–11
El Paso Electric	60	10,760	U	386	1	21,467	–3	–68	+14
Kansas City Power & Light	61	10,756	D	5,795	95	778	+11	–27	–44
Kentucky Utilities	62	10,762	U	4,335	2	2	–1	0	–33
Minnesota Power	63	10,773	D	3,935	0	0	+35	0	0
Wisconsin Public Service	64	10,782	D	3,034	353	26	+1	+4	–88
Northeast Utilities	65	10,790	U	420	12,868	5,722	+12	+10	+142
Oklahoma Gas & Electric	66	10,810	U	6,340	32	119,881	+20	+113	–15
Arizona Public Service	67	10,841	D	7,569	36	8,136	+3	–78	–3
Southern California Edison	68	10,851	D	5,160	1,107	228,904	–1	–88	+6
Tucson Electric Power	69	10,859	D	2,254	383	2,417	–24	+29	+10
Iowa-Illinois Gas & Electric	70	10,866	D	1,946	14	633	+5	+8	–43
Middle South Utilities	70	10,868	D	4,924	293	256,478	–5	–47	+10
Wisconsin Electric Power	72	10,869	D	5,951	101	540	+5	–39	–69
Washington Water Power	73	10,870	U	1,039	116	19	+52	–3	–
Northern States Power	74	10,872	U	7,517	29	457	+5	–79	+10
Pacific Gas & Electric	75	10,905	D	0	834	248,138	0	–56	+31
Public Service of Colorado	76	10,907	U	6,901	28	1,482	+1	–70	+19
Empire District Electric	77	10,927	U	1,216	5	618	+7	–88	+26
Philadelphia Electric	78	10,940	U	2,933	8,237	1,147	+13	–6	+107
Texas Utilities	79	10,952	D	20,611	408	386,828	+1	–61	+18
Central Maine Power	80	10,988	U	0	2,514	0	0	–	0
Northern Indiana Public Service	81	11,002	D	4,623	41	882	–9	–55	–62
Public Service of New Mexico	82	11,022	D	4,022	29	104	–13	+200	–84
Pacificorp	83	11,043	D	11,094	74	0	+16	+16	0
Madison Gas & Electric	84	11,061	D	828	5	1,074	–3	0	–16
Nevada Power	85	11,083	D	2,598	43	3,207	+11	–7	+62
Commonwealth Edison	86	11,085	U	14,337	4,432	2,773	–18	–33	–83
Iowa Resources	87	11,148	U	1,991	12	666	–2	–54	–
Portland General Electric	88	11,150	D	1,001	0	0	+61	0	0
Kansas Gas & Electric	89	11,161	U	3,520	1	10,935	+19	–80	–17
Puget Sound Power & Light	90	11,210	U	2,188	1	18	+65	–60	–38
Montana Power	91	11,228	U	1,960	12	346	+68	–97	–63
Consolidated Edison	92	11,319	U	0	17,610	87,674	0	–21	+30
Interstate Power	93	11,508	U	1,963	18	950	–7	–28	–15
Kansas Power & Light	94	11,582	D	5,915	27	2,442	+7	–69	–48
Iowa Electric Light & Power	95	11,586	U	693	15	236	–28	–21	–13
Otter Tail Power	96	11,633	D	1,946	1	0	+3	–67	0
Centel	97	12,252	U	866	5	5,279	+15	–49	–32
Montana-Dakota Utilities	98	12,438	D	1,577	5	57	–2	–61	+66
Central Vermont Public Service	99	13,014	U	66*	40	0	–	+9	0
TNP Enterprises	100	18,806	U	0	0	62	0	–100	+130

*Wood

reported in the Uniform Statistical Reports are shown in Table 4. Table 5 shows the leaders in fossil-boiler heat rate. (This eliminates the effect of nuclear plants, gas turbines, and diesel engines on heat rate.)

Peaks up slightly

Data presented in the second large table, and summarized in table 2, show that peak demand rose only slightly in 1984. A slower pace of economic growth than in 1983 and a relatively cool summer (following a heat wave in 1983) led to modest increases. The leaders:

- Pennsylvania Power & Light...up 13.3 percent to 5519 MW,
- San Diego Gas & Electric...up 13.2 percent to 2342 MW,
- Southern California Edison...up 12.8 percent to 15,189 MW,
- Texas Utilities...up 8.8 percent to 15,265 MW,
- Boston Edison...up 6.9 percent to 2387 MW,
- Tucson Electric Power...up 6.4 percent to 1031 MW,
- Nevada Power...up 6.3 percent to 1537 MW,
- Orange & Rockland...up 6.2 percent to 767 MW,
- American Electric Power...up 6.1 percent to 20,669 MW,
- Allegheny Power System...up 6.0 percent to 5508 MW,
- Commonwealth Energy System...up 6.0 percent to 703 MW.

In past decades utilities averaged 6

TABLE 4
TOP 20 GENERATING UNITS—BY HEAT RATE (CF > 50%)

	Unit	Capacity (MW)
1.	Marshall 3	630
2.	Brayton 3	632
3.	Canal 1	568
4.	Belews Creek 2	1120
5.	Eastlake 5	446
6.	Marshall 2	385
7.	Marshall 4	630
8.	Belews Creek 1	1120
9.	Marshall 1	385
10.	Trenton Channel 9	500
11.	Bayshore 4	215
12.	Bayshore 3	142
13.	Crystal River 4	717
14.	Mountaineer 1	1300
15.	Amos 2	800
15.	Stuart 4	205
17.	Bayshore 1	136
18.	Morgantown 2	582
19.	Monroe 1	750
20.	Amos 1	800

percent gains in peak demand. Now 6 percent is good enough to make the top 10.

Summer weather was mild in 1984 but winter weather was even milder. There were only 17 winter peakers last year, down from 19 in 1983 and 32 in 1982.

Balanced seasonal demand and rising industrial consumption are improving load factors. Average load factor (unweighted) climbed from 57.5 in 1982 to 57.7 in 1983 and 59.6 last year.

> ***"Summer weather was mild in 1984, but winter weather was even milder."***

Capacity growth stalled

The data in Table 2 show that while peak demand isn't growing much, it's growing faster than generating capacity which has stabilized in recent years for the top 100.

In the past five years, the top 100's system capability has grown at the rate of about one percent, or 5000 MW, a year. The group's system reserve margin has declined from a high of 29 percent in 1982 to 24 percent in 1984. It should be noted that reserve margins for the electric utility industry as a whole are somewhat higher

Utility	Heat rate (Btu/kWh)
Duke Power	8960
New England Electric	9090
Commonwealth Energy	9098
Duke Power	9110
Cleveland Electric Illuminating	9110
Duke Power	9129
Duke Power	9133
Duke Power	9146
Duke Power	9155
Detroit Edison	9206
Toledo Edison	9278
Toledo Edison	9305
Florida Progress	9310
American Electric Power	9317
American Electric Power	9325
Dayton Power & Light	9325
Toledo Edison	9333
Potomac Electric Power	9342
Detroit Edison	9344
American Electric Power	9392

PEAK DEMAND AND CAPABILITY

Company	System Peak (MW)	% Change	Winter (W) or Summer (S)	Total System Capacity MW (at time of peak)	Total System Reserve %	Owned Capacity MW (at time of peak)	Owned Reserve %	Load Factor %
Allegheny Power System	5,507	+6.0	W	NA	—	7,138	30	69.3
American Electric Power	20,669	+6.1	S	19,814	–4	21,346	3	66.1
Arizona Public Service	2,970	+2.4	S	3,344	13	3,150	6	54.9
Atlantic Electric	1,299	–3.6	S	1,594	23	1,481	14	58.1
Baltimore Gas & Electric	4,235	+3.7	S	5,490	30	5,371	27	55.2
Boston Edison	2,387	+6.6	S	2,381	0	2,724	14	57.8
Carolina Power & Light	6,490	–1.0	S	8,200	25	8,256	28	59.5
Central	578	–1.8	S	NA	NA	659	14	NA
Central & South West	9,810	+0.7	S	12,645	29	12,217	24	55.9
Central Hudson Gas & Electric	695	+3.9	S	1,080	56	990	42	65.9
Central Illinois Light	934	–5.0	S	1,287	38	1,287	38	56.4
Central Illinois Public Service	1,780	–9.6	S	2,900	63	2,780	56	59.5
Central Louisiana Electric	1,010	–0.5	S	1,452	44	1,445	43	56.0
Central Maine Power	1,288	–0.1	W	NA	—	957	–26	72.1
Central Vermont Public Service	410	+5.7	S	449	10	98	–76	63.5
Cincinnati Gas & Electric	3,100	–0.2	S	4,030	30	4,030	30	60.0
Cleveland Electric Illuminating	3,371	–1.0	S	3,694	10	3,694	10	64.5
Commonwealth Edison	14,072	+0.4	S	17,027	21	16,963	16	53.4
Commonwealth Energy System	702	+0.0	S	831	18	225	68	63.3
Consolidated Edison	7,420	+0.5	S	10,462	41	9,387	26	49.7
Consumers Power	4,837	+1.5	S	6,099	26	6,392	32	66.5
Dayton Power & Light	2,106	–2.2	W	2,683	27	2,687	28	60.8
Delmarva Power & Light	1,576	–0.3	S	2,172	38	2,172	38	64.1
Detroit Edison	7,350	+6.1	S	9,271	26	8,700	18	60.2
Dominion Resources	8,895	–5.4	S	11,231	26	10,115	14	59.8
Duke Power	11,040	–4.6	S	13,782	25	13,584	23	62.2
Duquesne Light	2,172	–0.5	S	2,993	38	3,073	41	63.8
Eastern Utilities Associates	716	+3.3	S	858	20	586	–22	60.4
El Paso Electric	776	+4.0	S	1,009	30	1,009	30	63.8
Empire District Electric	520	–0.2	S	620	19	622	19	54.2
Florida Progress (FPC)	4,856	–1.1	W	6,300	30	6,100	26	48.5
FP&L Group (FP&L)	10,270	–3.8	S	11,761	15	13,470	31	58.9
General Public Utilities	6,401	+4.3	S	8,702	36	7,757	21	NA
Gulf States Utilities	5,475	+2.4	S	6,780	24	6,504	19	69.0
Hawaiian Electric	1,131	–0.3	W	1,596	41	1,495	32	72.6
Houston Industries	10,861	+1.0	S	13,250	22	12,275	13	63.0
Idaho Power	2,189	+6.2	S	2,689	23	2,519	15	62.0
Illinois Power	3,217	+0.1	S	3,672	14	3,717	16	58.3
Interstate Power	764	–2.0	S	953	25	950	24	62.1
Iowa Electric Light & Power	967	–1.0	S	1,147	19	996	3	53.9
Iowa Resources	1,156	–4.4	S	1,420	23	1,331	15	48.3
Iowa-Illinois Gas & Electric	994	–2.7	S	1,433	44	1,539	55	50.9
IPALCO	2,043	–1.1	S	2,406	18	2,406	18	57.0
Kansas City Power & Light	2,297	–1.2	S	2,647	15	2,477	8	47.2
Kansas Gas & Electric	1,562	–3.2	S	2,027	30	2,084	33	52.6
Kansas Power & Light	1,802	–2.8	S	2,469	37	2,681	49	49.0
Kentucky Utilities	2,193	–0.6	W	2,935	33	2,678	22	58.6
Long Island Lighting	3,096	–0.4	S	3,721	20	3,778	22	NA
Louisville Gas & Electric	1,749	–7.2	S	2,343	34	2,343	34	53.5
Madison Gas & Electric	427	+0.2	S	553	30	589	38	58.0
Middle South Utilities	10,456	–3.8	S	13,987	34	14,126	35	61.3
Midwest Energy	768	–7.1	S	1,262	64	1,262	64	48.5
Minnesota Power	1,051	+2.0	S	1,803	72	1,395	33	78.0
Missouri Public Service	742	+0.4	S	906	22	906	22	43.5
Montana-Dakota Utilities	355	+0.3	S	406	14	406	14	58.2
Montana Power	1,221	–10.0	W	1,544	26	1,314	8	67.0
Nevada Power	1,537	+6.3	S	1,862	21	1,750	14	49.2
New England Electric	3,370	+4.5	S	4,152	23	3,875	15	61.7
New York State Electric & Gas	2,254	+3.6	W	3,130	39	2,444	8	67.3
Niagara Mohawk Power	5,530	–1.0	W	7,701	39	5,315	–4	89.3
Northeast Utilities	4,224	+4.7	S	5,912	40	6,215	47	62.4
Northern Indiana Public Service	2,272	–3.6	S	3,430	51	3,030	33	65.3
Northern States Power	5,544	+2.9	S	6,457	16	5,924	7	57.5
Ohio Edison	4,097	–1.3	S	5,699	39	5,416	32	68.4
Oklahoma Gas & Electric	4,700	+3.5	S	5,860	25	5,814	24	51.0
Orange & Rockland	767	+0.2	S	1,028	34	1,011	32	50.5
Otter Tail Power	546	0	W	649	19	596	9	59.7
Pacific Gas & Electric	14,225	+1.4	S	18,069	27	12,617	–11	70.7
PacifiCorp	4,246	–2.1	W	5,433	28	3,863	–9	61.0
Pennsylvania Power & Light	5,510	+13.3	W	7,494	36	7,415	34	61.4
Philadelphia Electric	5,925	+0.8	S	7,753	31	7,753	31	57.7
Portland General Electric	2,862	–9.6	W	4,202	47	2,558	11	55.4
Potomac Electric Power	4,490	+4.8	S	5,368	20	5,368	20	50.7
Public Service Electric & Gas	7,422	+2.5	S	9,300	25	8,999	21	52.4
Public Service of Colorado	2,968	0	S	3,700	25	3,036	2	68.3
Public Service of Indiana	3,683	–2.0	S	5,877	60	5,627	54	61.1
Public Service of New Hampshire	1,202	–1.5	W	1,433	19	1,290	8	62.4
Public Service of New Mexico	970	–2.2	S	1,479	52	1,479	52	69.4
Puget Sound Power & Light	3,491	–11.2	W	4,028	16	1,688	–62	50.2
Rochester Gas & Electric	1,075	+3.7	S	1,532	43	1,151	7	63.9
San Diego Gas & Electric	2,342	+13.2	S	2,759	18	2,471	6	55.9
Savannah Electric & Power	481	–1.0	S	670	39	600	25	54.2
Sierra Pacific Resources	708	+5.0	S	968	37	589	–17	69.2
South Carolina Electric & Gas	2,596	–3.9	S	3,056	18	3,959	53	58.0
Southern California Edison	15,189	+12.8	S	16,938	12	14,841	–2	53.1
Southern Company	19,772	–3.6	S	26,165	32	24,856	26	58.9
Southern Indiana Gas & Electric	902	–0.3	S	917	2	917	2	55.0
Southwestern Public Service	2,762	+7.0	S	3,586	30	3,586	30	65.3
Teco Energy	2,172	+3.8	W	2,578	19	2,578	19	62.2
Texas Utilities	15,285	+6.6	S	17,914	17	17,810	17	54.4
TNP Enterprises	NA	NA	NA	NA	NA	NA	NA	NA
Toledo Edison	1,327	+0.2	S	1,726	30	1,688	27	58.2
Tucson Electric Power	1,031	+6.4	S	1,127	9	1,326	29	58.3
Union Electric	6,543	+3.8	S	7,629	17	6,669	2	53.2
United Illuminating	999	+3.0	S	1,225	23	1,225	23	57.3
Utah Power & Light	3,229	+3.3	S	2,969	–8	3,165	–2	70.2
Washington Water Power	1,469	–11.6	W	1,859	27	1,381	–6	54.9
Wisconsin Electric Power	3,684	+3.6	S	3,940	7	4,034	10	60.0
Wisconsin Power & Light	1,426	+1.6	S	1,780	25	1,625	14	63.0
Wisconsin Public Service	1,203	+3.2	S	1,673	39	1,661	38	73.6

TYPE OF GENERATION IN THE SYSTEM

Company	Fossil MW	Fossil %	Fossil Last Year Change MW	Hydro & Pump Storage MW	Hydro & Pump Storage %	Hydro & Pump Storage Last Year Change MW	Combustion Turbines MW	Combustion Turbines %	Combustion Turbines Last Year Change MW	Nuclear MW	Nuclear %	Nuclear Last Year Change MW
Allegheny Power System	7,047	99	−29	62	1	0	0	0	0	0	0	0
American Electric Power	19,800	87	+1445	836	4	0	85	1	−103	2130	9	0
Arizona Public Service	2,644	84	−122	6	1	0	501	16	0	0	0	0
Atlantic Electric	794	54	+48	0	0	0	368	25	0	319	22	0
Baltimore Gas & Electric	3,038	56	+536	0	0	0	717	13	0	1650	31	0
Boston Edison	1,887	66	+18	0	0	0	247	9	−66	670	25	0
Carolina Power & Light	5,088	61	0	214	3	0	1018	12	0	1955	24	0
Centel	530	82	−56	0	—	—	120	18	0	0	—	—
Central & South West	12,788	100	+672	0	0	0	0	0	0	0	0	0
Central Hudson Gas & Electric	894	81	+1	43	4	0	42	4	0	0	0	0
Central Illinois Light	1,255	98	0	0	0	0	32	2	0	0	0	0
Central Illinois Public Service	2,773	2	+99	0	0	0	3	1	0	0	0	0
Central Louisiana Electric	1,361	100	−121	0	0	0	0	0	−23	0	0	0
Central Maine Power	590	62	−59	323	34	−5	45	4	+45	0	0	0
Central Vermont Public Service	26	26	+11	40	41	+1	32	33	0	0	0	0
Cincinnati Gas & Electric	3,566	88	0	0	0	0	475	12	0	0	0	0
Cleveland Electric Illuminating	2,880	78	−647	305	8	0	62	2	0	447	12	0
Commonwealth Edison	9,703	52	+60	624	3	0	1331	7	0	7007	38	+1078
Commonwealth Energy System	1,023	94	0	0	0	0	62	6	0	0	0	0
Consolidated Edison	6,552	69	+108	0	0	0	2080	22	+13	849	9	0
Consumers Power	4,193	64	+8	1089	17	0	477	7	0	826	13	+6
Dayton Power & Light	2,291	92	−4	0	0	0	210	8	+27	0	0	0
Delmarva Power & Light	1,737	78	0	0	0	0	170	8	+26	319	14	0
Detroit Edison	7,231	83	+363	918	11	0	530	6	0	0	0	0
Dominion Resources	6,020	61	−6	326	3	0	439	4	0	3124	32	+12
Duke Power	6,603	48	−887	1452	11	0	589	4	0	4940	37	+1180
Duquesne Light	2,763	88	—	0	0	0	0	0	0	385	12	0
Eastern Utilities Associates	509	92	0	0	0	0	47	8	0	0	0	0
El Paso Electric	920	93	−1	0	0	0	68	7	0	0	0	0
Empire District Electric	412	66	0	16	3	0	195	31	0	0	0	0
Florida Progress (FPC)	4,204	64	+762	0	0	0	1571	24	−134	761	12	+9
FP&L Group (FP&L)	8,186	63	0	0	0	0	1977	15	0	2823	22	0
General Public Utilities	4,101	49	0	357	4	–	1487	18	−386	2356	28	0
Gulf States Utilities	6,264	99	−27	0	0	0	90	1	0	0	0	0
Hawaiian Electric	1,274	86	0	0	0	0	219	14	+4	0	0	0
Houston Industries	11,101	90	+241	0	0	0	1174	10	−162	0	0	0
Idaho Power	858	33	0	1671	65	+13	50	2	0	0	0	0
Illinois Power	3,562	95	−64	2	—	0	178	5	0	0	0	0
Interstate Power	886	94	+25	0	0	0	56	6	0	0	0	0
Iowa Electric Light & Power	541	62	+80	0	0	0	158	15	−2	360	33	0
Iowa Resources	1,054	79	0	0	0	0	275	21	0	0	0	0
Iowa-Illinois Gas & Electric	1,085	69	+1	3	–	0	68	4	0	384	24	0
IPALCO	2,322	97	−141	0	0	0	74	3	+9	0	0	0
Kansas City Power & Light	2,107	85	−157	0	0	0	370	15	0	0	0	0
Kansas Gas & Electric	2,060	99	−23	0	0	0	23	1	0	0	0	0
Kansas Power & Light	2,342	87	0	0	0	0	339	13	0	0	0	0
Kentucky Utilities	3,082	97	+611	24	1	0	60	2	0	0	0	0
Long Island Lighting	NA	—	—	NA	—	—	NA	—	—	NA	—	—
Louisville Gas & Electric	2,133	95	−104	0	0	0	109	5	0	0	0	0
Madison Gas & Electric	406	68	−4	0	0	0	92	16	0	95	16	+3
Middle South Utilities	12,664	85	+475	69	1	0	387	3	−13	1694	11	0
Midwest Energy	1,053	83	+89	0	0	0	209	17	+1	0	0	0
Minnesota Power	1,285	93	0	109	7	0	0	0	0	0	0	0
Missouri Public Service	610	67	+4	0	0	0	296	33	0	0	0	0
Montana-Dakota Utilities	348	80	0	0	0	0	86	20	0	0	0	0
Montana Power	789	60	+210	520	40	0	5	—	0	0	0	0
Nevada Power	1,312	75	0	0	0	0	438	25	0	0	0	0
New England Electric	2,648	68	+1	1175	30	+2	56	2	0	0	0	0
New York State Electric & Gas	2,376	97	+843	60	2	+4	8	1	−2	0	0	0
Niagara Mohawk Power	3,706	68	+5	694	13	0	369	7	+59	642	12	+32
Northeast Utilities	2,485	43	0	1275	22	+9	501	9	−22	1520	26	0
Northern Indiana Public Service	2,801	92	+22	10	1	0	241	7	0	0	0	0
Northern States Power	3,264	55	+22	224	4	+2	928	17	+2	1539	28	0
Ohio Edison	4,791	89	+18	0	0	0	139	3	−3	425	8	0
Oklahoma Gas & Electric	5,598	99	+403	0	0	0	59	1	0	0	0	0
Orange & Rockland	902	89	0	34	3	0	74	7	0	0	0	0
Otter Tail Power	504	85	0	4	1	−1	87	15	0	0	0	0
Pacific Gas & Electric	8,527*	75	+252	2612	22	+6	394	3	0	0	0	0
Pacificorp	3,052	75	+70	976	24	0	0	0	0	27	1	0
Pennsylvania Power & Light	5,786	78	+100	146	2	0	539	7	0	945	13	0
Philadelphia Electric	3,367	43	−22	1290	17	−102	1280	17	−82	1816	23	0
Portland General Electric	1,130	44	–	601	23	–	122	5	–	729	28	–
Potomac Electric Power	4,809	90	+4	0	0	0	566	10	+4	0	0	0
Public Service Electric & Gas	4,312	48	0	165	2	0	2700	30	−5	1817	20	0
Public Service of Colorado	2,462	81	−68	186	6	+71	186	6	−1	200	7	0
Public Service of Indiana	5,411	95	0	95	1	0	221	4	0	0	0	0
Public Service of New Hampshire	1,096	85	+7	69	6	+4	118	9	−65	0	0	0
Public Service of New Mexico	1,317	98	−80	0	0	0	28	2	−2	0	0	0
Puget Sound Power & Light	683	40	+175	310	19	0	702	41	+247	0	0	0
Rochester Gas & Electric	587	52	−18	47	4	0	28	3	0	470	41	0
San Diego Gas & Electric	1,854	69	+102	0	0	0	333	12	0	515	19	+214
Savannah Electric & Power	537	88	0	0	0	0	72	12	0	0	0	0
Sierra Pacific Resources	591	86	0	12	2	0	86	13	−1	0	0	0
South Carolina Electric & Gas	2,418	61	0	756	19	0	185	5	0	600	15	0
Southern California Edison	10,370	70	0	929	6	0	1632	11	0	1962	13	+788
Southern Company	18,831	76	+117	2385	10	+66	1131	4	−34	2375	10	−13
Southern Indiana Gas & Electric	782	85	−87	0	0	0	135	15	0	0	0	0
Southwestern Public Service	3,480	97	0	0	0	0	108	3	0	0	0	0
Teco Energy	2,435	94	+15	0	0	0	158	6	0	0	0	0
Texas Utilities	17,804	100	0	0	0	0	0	0	−6	0	0	0
TNP Enterprises	39	78	0	0	0	0	11	22	0	0	0	0
Toledo Edison	1,199	71	−24	0	0	0	66	−1	−11	423	25	−5
Tucson Electric Power	1,108	84	−240	0	0	0	218	16	0	0	0	0
Union Electric	5,579	72	0	631	8	0	391	5	+2	1120	15	+1120
United Illuminating	1,216	98	−6	0	0	0	22	2	0	0	0	0
Utah Power & Light	3,049*	96	+20	127	4	+1	19	1	0	0	0	0
Washington Water Power	344	25	+106	946	68	0	101	7	0	0	0	0
Wisconsin Electric Power	2,701	68	−24	7	1	0	290	7	0	970	24	−20
Wisconsin Power & Light	1,183	74	−3	42	3	0	176	11	+2	214	13	0
Wisconsin Public Service	1,234	74	−3	54	3	−2	157	9	−33	216	13	+1

*Includes geothermal capacity

than for the 100 largest IOUs.

However, the reserve margin for the top 100 has been declining at the rate of about two percentage points a year since the last recession bottomed out. The reserve margin is large enough to support this trend for quite a while, but the leadtime required to build new generation suggests that utilities begin looking once again at capacity planning.

New nukes

The data in the third large table, summarized in table 3, show that additions of new nuclear and coal-fired base-load capacity are being largely offset by retirements and downratings of older fossil-fired steam capacity and gas turbines.

The only clear trend that shows up in the generation table is the growth of nuclear capacity over the last few years. Nuclear capacity at the top 100 climbed 11 percent in 1984 and 8 percent in 1983—the only generating type to show a significant gain in two years.

The leading nuclear utilities:

- Commonwealth Edison...7007 MW of nuclear capacity,
- Duke Power...4940 MW,
- Dominion Resources...3124 MW,
- FP&L...2823 MW,
- Southern Company...2375 MW,
- General Public Utilities...2356 MW,
- American Electric Power...2130 MW,
- Southern California Edison...1962 MW,
- Carolina Power & Light...1955 MW,
- Public Service Electric & Gas...1817 MW,
- Philadelphia Electric...1816 MW,
- Middle South Utilities...1964 MW,
- Baltimore Gas & Electric...1650 MW,

TABLE 5
SYSTEM HEAT RATE LEADERS—FOSSIL-FUELED BOILERS ONLY

	Utility	Heat rate (Btu/kWh)
1.	Duke Power	9318
2.	Commonwealth Energy	9636
3.	Consumers Power	9690
4.	American Electric Power	9766
5.	Toledo Edison	9850
6.	Florida Progress	9883
7.	South Carolina Electric & Gas	9941
8.	Dayton Power & Light	9947
9.	United Illuminating	9955
10.	Cincinnati Gas & Electric	9988

- Northern States Power...1539 MW, and
- Northeast Utilities...1520 MW.

T&D additions

No particular trends are evident in the T&D data. Unfortunately, data reporting is not consistent enough to allow summarization of the T&D information.

Utilities with the largest additions to their high voltage transmission systems (above 189 kV) in 1984 are:

- FP&L...499 circuit miles added,
- Portland General Electric...494 circuit miles,
- San Diego Gas & Electric...363 circuit miles,
- Central & South West...222 circuit miles, and
- Middle South Utilities...211 circuit miles.

Utilities that added the most to transmission systems at lower voltages (below 189 kV):

- Commonwealth Edison...374 circuit miles added,
- Puget Sound Power & Light...315 pole miles added,
- Union Electric...133 circuit miles added,
- Kentucky Utilities...129 circuit miles, and
- Illinois Power...91 circuit miles.

For overhead distribution, above 22 kV, utilities showing the most growth are Central and Southwest, which added 230 pole miles, and Delmarva Power & Light, which added 229 pole miles. For lower voltage overhead distribution, less than 22 kV, the growth leaders were:

- Union Electric...3035 pole miles added,
- Middle South Utilities...1351 pole miles,
- Central & South West...724 pole miles,
- Texas Utilities...456 pole miles, and
- Houston Industries...399 pole miles.

For underground distribution at voltage levels above 22kV, the leaders are Southwestern Public Service with 252 added cable miles and Delmarva Power & Light with 235 added cable miles. For underground distribution at voltages below 22 kV the leaders are:

- Southern California Edison...1242 added cable miles,
- Public Service Electric & Gas...1068 added cable miles,
- Allegheny Power System...546 added cable miles,
- Florida Progress...487 added cable miles,
- Northern States Power...467 added cable miles, and
- Union Electric...467 added.

TRANSMISSION AND DISTRIBUTION LINES IN OPERATION

	Transmission				Distribution							
					Overhead				Underground			
Company	189 kV & Up (circuit miles)	Miles Added	Below 189 kV (circuit miles)	Miles Added	22 kV & Up (pole miles)	Miles Added	Below 22 kV (pole miles)	Miles Added	22 kV & Up (cable miles)	Miles Added	Below 22 kV (cable miles)	Miles Added
Allegheny Power System	889	1	3,338	35	4,520	–27	48,263	270	11	2	2,449	546
American Electric Power	5755	–	15,730	–	3,911	73	92,233	346	246	9	5,591	167
Arizona Public Service	2384†	120	2,274†	19	0	–	10,420	70	0	0	5,236	389
Atlantic Electric	64	0	1,165	3	0	0	5,910	31	0	0	704	40
Baltimore Gas & Electric	489	0	604	0	740	3	51,234^	–	163	2	18,530	–
Boston Edison	160	0	190	0	0	0	3,377	4	0	0	7,173	0
Carolina Power & Light	2829	197	3,038	–7	36,446*	226*	–	–	2,848*	244*	–	–
Centel	2973*	–1*	–	–	6,662*	28*	–	–	608*	18*	–	–
Central & South West	1335	222	10,027	–4197	467	230	53,861	724	249	249	4,993	79
Central Hudson Gas & Electric	76	0	527	6	44	0	6,287	24	0	0	692	27
Central Illinois Light	47	0	283	–3	627	–1	5,619	–16	7	0	1,652	28
Central Illinois Public Service	305	0	4,230	–1	0	0	8,282	7	0	0	605	24
Central Louisiana Electric	298	0	767	0	10,268	100	0	–	174*	4*	–	–
Central Maine Power	NA	–	NA	–	NA	–	NA	–	NA	–	NA	–
Central Vermont Public Service	0	0	615	0	0	0	7,012	45	0	0	93	8
Cincinnati Gas & Electric	383	4	1,331	–46	490	7	8,915	12	23	2	1,663	65
Cleveland Electric Illuminating	358	–1	1,997	0	0	0	9,452	18	0	0	4,982	16
Commonwealth Edison	2433	50	2,818	374	35,646*	59*	–	–	20,556*	500*	–	–
Commonwealth Energy System	60	0	293	0	1,448	34	3,295	16	731	43	2,017	57
Consolidated Edison	409	–1	22	0	389	35	25,560	–136	6,359	49	58,000	–107
Consumers Power	1913	0	7,930	–1	47,217*	215*	–	–	6,019*	157*	–	–
Dayton Power & Light	448	–	1,322	–	NA	–	NA	–	NA	–	NA	–
Delmarva Power & Light	263	–1	1,107	45	4,811	229	1,761	–714	1,588	235	697	294
Detroit Edison	968	0	4,407	5	0	0	29,535	86	0	0	6,867	62
Dominion Resources	2735	69	2,953	31	38,228*	189*	–	–	11,541*	468*	–	–
Duke Power	3009	29	10,191	1052	8,982	105	46,478	393	1,655	147	3,275	208
Duquesne Light	508	3	132	–	NA	–	NA	–	NA	–	NA	–
Eastern Utilities Associates	75	0	289	0	64	–1	3,431	96	6	0	867	16
El Paso Electric	633	171	654	0	1,301	30	2,921	28	83	19	665	21
Empire District Electric	0	0	1,227	37	0	0	4,583	61	0	0	213	9
Florida Progress (FPC)	1467	74	2,714	–6	0	0	15,877	151	0	0	5,899	487
FP&L Group (FP&L)	2993	499	2,235	0	33,132*	625*	–	–	10,228*	693*	–	–
General Public Utilities	2068	24	4,427	6	4,729	138	40,119	25	1,290	61	10,543	415
Gulf States Utilities	1149	–	3,549	–	1,203	–	18,322	–	379	–	1,523	–
Hawaiian Electric	0	0	1,292	12	0	0	3,740	11	0	0	2,220	60
Houston Industries	935	177	2,468	23	936	65	17,650	399	797	111	3,916	213
Idaho Power	1481†	30	3,177†	–52	4,008	97	13,020	–35	142	15	4,255	140
Illinois Power	485	0	2,448	91	1,349	18	16,466	50	4	0	983	14
Interstate Power	69	0	2,604	–11	NA	–	NA	–	0	0	500	10
Iowa Electric Light & Power	67	0	3,211	–21	0	0	4,704	6	0	0	1,566	64
Iowa Resources	345	–	1,177	–	0	0	11,225	10	0	0	1,980	87
Iowa-Illinois Gas & Electric	305	42	640	0	0	0	3,323	32	0	0	1,071	48
IPALCO	419	0	617	0	0	0	4,640	23	0	0	3,564	120
Kansas City Power & Light	295	0	1,356	24	0	0	8,814	16	0	0	4,336	277
Kansas Gas & Electric	663	98	1,574	–1	0	0	7,743	3	0	0	1,7[illegible]2	97
Kansas Power & Light	778	–	3,596	–	0	0	12,248	86	0	0	402	17
Kentucky Utilities	477	44	4,248	129	0	0	13,930	89	0	0	0	0
Long Island Lighting	NA	–	NA	–	NA	–	NA	–	NA	–	NA	–
Louisville Gas & Electric	131	0	758	0	86	–1	3,264	15	0	0	1,763	44
Madison Gas & Electric	124	0	177	–2	0	0	1,076	0	0	0	526	23
Middle South Utilities	2360	211	7,459	28	4,500	–1112	64,825	1351	1,518	54	2,731	206
Midwest Energy	191	–3	2,216	6	NA	–	NA	–	NA	–	NA	–
Minnesota Power	606†	0	1,503†	0	760	–2	3,890	–6	0	0	832°	90°
Missouri Public Service	58†	0	1,280†	20	0	0	4,662	13	0	0	494	27
Montana-Dakota Utilities	305	39	2,851	–19	0	0	2,834	10	0	0	1,620	83
Montana Power	1449	–22	5,409	–62	0	0	12,733	168	0	0	1,019°	48
Nevada Power	613	0	458	0	0	0	2,636	20	0	0	2,500	122
New England Electric	602	0	1,977	–3	786	1	16,143	97	200	1	6,668	148
New York State Electric & Gas	813	–	3,792	–	2,110	–	30,018	–	1,547*	14*	–	–
Niagara Mohawk Power	1116	0	8,083	–61	107,517*†	172*†	–	–	6,603*	93*	–	–
Northeast Utilities	450	–	1,615	–	20,813*	51*	–	–	5,456*	164*	–	–
Northern Indiana Public Service	332	0	2,615	23	0	0	7,605	–41	0	0	627	+29
Northern States Power	1445	0	5,445	+22	0	0	25,022	1	0	0	10,036	+467
Ohio Edison	522	–52	4,928	57	0	0	24,577	52	0	0	2,710	93
Oklahoma Gas & Electric	926	115	3,535	–11	19,203*	161*	–	–	5,023*	253*	–	–
Orange & Rockland	80	0	473	–5	0	0	4,614	41	0	0	883	49
Otter Tail Power	407	38	5,033	4	147	0	888	–39	21	0	1,396	47
Pacific Gas & Electric	6391	–	11,443	–	85,494*	3700*	–	–	10,759*°	–	–	–
Pacificorp	3226	0	3,764	–83	27,612*	73*	–	–	7,093*	227*	–	–
Pennsylvania Power & Light	0	0	1,307	–5	2,343	5	46,877	348	10	0	6,326	299
Philadelphia Electric	720	47	365	0	61	0	11,742	68	17	0	14,863	230
Portland General Electric	1038	494	943	–1	0	–	8,758	–	0	0	3,745	62
Potomac Electric Power	773	0	26	0	295	0	4,556	6	787	11	9,334	551
Public Service Electric & Gas	680	0	1,756	–46	NA	–	14	0	109	0	20,560	1068
Public Service of Colorado	1275	–	1,638	–	1,399	–	11,542	–	187	–	4,114	–
Public Service of Indiana	1472	0	4,024	–27	0	0	18,129	11	0	0	2,151	112
Public Service of New Hampshire	283	0	1,458	–6	9,311*	–20*	–	–	459*	16*	–	–
Public Service of New Mexico	1754	–	879	–	0	0	4,404	75	0	0	1,786	130
Puget Sound Power & Light	337†	1	1,762†	315†	11,870*	–560*	–	–	4,620*	262*	–	–
Rochester Gas & Electric	0	0	709	8	0	0	6,668	64	0	0	4,158	63
San Diego Gas & Electric	606	363	1,107	9	0	0	7,250	19	0	0	6,002	4
Savannah Electric & Power	39	0	56	2	291	1	2,229	28	–	–	–	–
Sierra Pacific Resources	906	11	2,392	10	7,302*	1152*	–	–	2,444*	511*	–	–
South Carolina Electric & Gas	749	9	2,367	30	7,088	69	5,874	53	41	–6	1,559	68
Southern California Edison	5160	–1	6,254	33	44,402*	314*	–	–	148	7	40,629	1242
Southern Company	5610	160	19,793	341	84,943*	825*	–	–	10,000*	456*	–	–
Southern Indiana Gas & Electric	0	0	803	–1	0	0	3,175	–1	0	0	656	37
Southwestern Public Service	1201	–	3,982	–	15,238	142	0	0	1,099	252	0	0
Teco Energy	353	–	757	–	0	0	6,407	62	0	0	1,571	106
Texas Utilities	3639	–11	8,696	26	2,785	147	47,471	456	943	173	6,879	443
TNP Enterprises	20	0	1,583	32	0	0	8,004	199	0	0	340	33
Toledo Edison	158†	0	1,025†	–1	7,666*	16*	–	–	741*	29*	–	–
Tucson Electric Power	1346	–	318	–	553	–	6,079	–	33	–	2,409	–
Union Electric	909	0	2,621	133	3,612	9	19,866	3035	337	1	7,419	467
United Illuminating	6	0	89	0	2	0	3,015	14	3	0	1,169	–9
Utah Power & Light	2079†	–3†	5,556†	28†	15,574*	1161*	–	–	2,703*°	269*°	–	–
Washington Water Power	545	0	1,523	46	580	4	8,717	14	0	0	1,245	58
Wisconsin Electric Power	686	–	1,808	–	22,190*	59*	–	–	7,645*	160*	–	–
Wisconsin Power & Light	107	0	2,699	60	0	0	16,751	51	0	0	1,015	–7
Wisconsin Public Service	124	0	1,569	0	16,413*	36*	–	–	3,234*	120*	–	–

*Total, all voltage levels †Pole miles ^Wire miles °Conduit bank miles

C8650-4

Volume 63, Number 9
September 1985

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

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U.S., China sign nuclear cooperation pact

Don Minner
Associate Editor

WASHINGTON, D.C.—A much-needed booster shot was given to the American nuclear power industry in July, when the U.S. and China signed a nuclear cooperation pact that will allow U.S. companies to compete for a potential $6 billion of contracts.

Signed July 23 by U.S. Secretary of Energy John S. Herrington and Chinese Vice Premier Li Peng, the agreement has been sent to Congress, where it must meet House and Senate approval.

"This agreement will go a long way toward opening foreign markets, specifically China, to the American nuclear power industry," said Herrington. "It could help to revitalize the nuclear industry in this country."

The agreement was originally initialed in April 1984 during President Reagan's trip to the People's Republic of China.

Want to double output

The Chinese have plans to double their energy output by the end of the century. DOE stated that China wants to construct as many as eight nuclear plants by the year 2000.

Explained Herrington, "If we take advantage of the many opportunities available to us for energy cooperation and trade, I believe energy can be a cornerstone of strong and prosperous economic ties between our two nations."

DOE said the agreement covers only non-sensitive commercial materials, facilities, components, technology or information exchanged under the accord, none of which can be transferred beyond the boundaries of the recipient nation.

In addition, went on DOE, none of the materials, facilities, components, technology or information exchanged can be used for any nuclear explosive device or any military purpose.

Atomic Industrial Forum (AIF) spokesman Don Winston called the agreement a "hunting license" for U.S. companies.

Building their own reactor

Winston pointed out that the Chinese are currently building a 300 MW reactor at Quingshan in the Hubei province, using their own technology. He said the project, which would be China's first nuclear plant, was started in 1982 and is supposed to be completed in 1989. According to Winston, China plans to build two 900 MW units at Guangdong. The first unit is scheduled to enter commercial operation in 1991 and Unit 2 is expected to go on-line sometime later in the 1990s.

He mentioned that two other 1,000 MW units, Sunan 1 and 2, are planned by the Chinese for southern Jiangsu province.

Winston said the French company Framatome has had serious discussions with the Chinese government about Unit 1 at Guangdong.

American companies are getting a late start on bidding for the Chinese plants. China has had nuclear cooperation agreements with West Germany, France and Japan for several years. Although it hasn't yet signed an agreement, Sweden is attempting to negotiate with China.

Now that the U.S. is involved, Winston believes about eight or nine companies from the four countries will be bidding to supply reactor technology to China.

Assuming that a nuclear plant can be built in China for half the price it can be constructed in the U.S., Winston speculated the four units China currently plans to build will cost about $1.5 billion apiece, resulting in a potential $6 billion in new business.

Winston said the Chinese have expressed an interest in obtaining pressurized water reactors.

"The American companies are coming in late, but they have a lot of technology to offer," said John Callebaut, director of development and governmental relations for the National Council for U.S./China Trade in Washington, D.C.

The council, whose members include Westinghouse and General Electric, helps arrange meetings between U.S. and Chinese companies.

Callebaut warned there may be a "little trouble" in getting the agreement by Congress, because of the accord's nuclear nonproliferation language. He said that some in Washington believe the U.S. didn't get a firm

Continued on page 2

Chinese Vice Premier Li Peng scrutinizes gauges at the New York Power Authority's Niagara Power project with Power Authority Chairman Richard M. Flynn during the premier's July U.S. visit.

EUA offers $65 million for Seabrook shares of 4 utilities

BOSTON—Four New England utilities are close to selling their combined 11.2 percent ownership of the Seabrook nuclear station to Eastern Utilities Associates (EUA).

Central Maine Power Co. (6%), Bangor (ME) Hydro-Electric Co. (2.2%), Maine Public Service Co. (1.5%), and Central Vermont Public Service Co. (1.6%) have signed letters of intent to sell their interest in the plant. EUA, which already owns 2.9 percent of the station, would become the third largest owner of the plant. Public Service of New Hampshire has 35.6 percent and United Illuminating Co., based in New Haven, CT owns 17.5 percent.

Other owners include two utilities in New Hampshire, six in Massachusetts and one in Connecticut.

If the deals are finalized, it should facilitate the necessary regulatory approvals needed to complete the troubled plant.

Central Maine spokesman Peter Thompson said the utility sent its letter of intent to the Maine Public Utilities Commission asking the PUC for a recommendation on how to proceed.

If the Maine PUC says the utility should stay involved in the Seabrook project, Thompson said the utility will consider retaining its interest.

EUA is a Boston-based holding company whose subsidiaries include Blackstone Valley Electric Co., Eastern Edison Co., Montaup Electric Co., and EUA Service Corp.

EUA Vice President of Corporate Relations Webster H. Francis said the company has offered $56 million for the plant interest of the three Maine utilities and $9 million for Central Vermont's share of Seabrook.

Francis said it will cost $54 million to complete the Maine companies' share of the plant and $9 million to finish Central Vermont's portion.

Francis said EUA will be paying 15 cents on the dollar, or about $1,100 per kilowatt for the four utilities' share of the station.

Montaup Electric Co., EUA's subsidiary, will continue to hold the company's original 2.9 percent ownership share of Seabrook. Francis said Mon-

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Sponsors abandon coal gas plant

BEAULAH, ND—Sponsors of the Great Plains coal gasification plant announced in late July that they were abandoning the project, leaving operations and responsibility for a $1.5 billion debt in the hands of the U.S. Dept. of Energy.

The abandonment was caused by a decision by Energy Secretary John Herrington not to support the sponsors' request for a $720 million operating subsidy from the Synthetic Fuels Corporation.

The sponsors said they faced debt payments of $500,000 a day and operating losses which were unacceptable. Under the terms of the federally guaranteed loan that provided 75 percent of the financing for the project, the sponsors turned it over to DOE one day before its formal "in-service" date of August 1.

The sponsors are Tenneco Inc., American Natural Resources Co., Transco Energy Co., MidCon Corpo-

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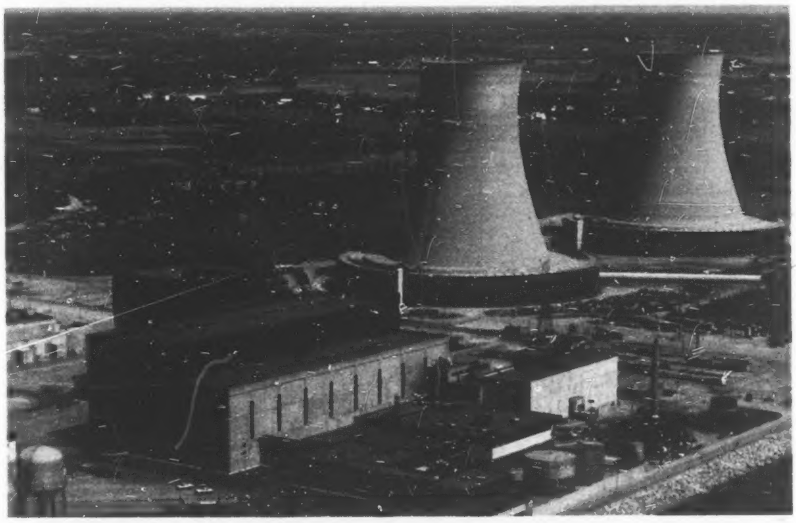

NRC approves Fermi 2 license

The Nuclear Regulatory Commission unanimously approved a full-power operation license for Detroit Edison's $3.6 billion Fermi 2 nuclear plant in July. The 1,100 MW plant is expected to reach 75 percent of its capacity in late October. It is currently undergoing low-power testing.

Foreign Power Briefs

● **The International Energy Agency** said governments and electric utilities in the industrialized countries should do more to overcome obstacles preventing electricity from making its full contribution to economic development and energy security. According to a new IEA report entitled *Electricity in IEA Countries: Issues and Outlook*, generating capacity in most IEA countries is now more than adequate to meet short-term demand. However, the study warned that future demand growth could absorb this surplus quickly . The report pointed out that much of the excess was accounted for by power plants that were old, oil-fired or environmentally unsuitable. The report said that sustained growth in IEA countries will require increased electricity generation. "Governments should ensure that legislative changes needed to reflect the changing environment in which the electricity industry operates are given high political priority," the study said. Member countries of the IEA are: the U.S., Canada, Japan, Australia, Austria, Belgium, Denmark, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the United Kingdom. Copies of the study are available for $46 from OECD Publications and Information Center, Suite 1207, 1750 Pennsylvania Ave., NW, Washington, D.C. 20006.

● **The Organization for Economic Cooperation and Development (OECD)** said the share of nuclear electricity generated in the industrialized western nations has, for the first time, exceeded the share produced by oil. According to OECD, nuclear generation now accounts for 18 percent of the power produced in OECD member countries, which include the U.S., Japan, Australia, New Zealand and western Europe. Atomic Industrial Forum President Carl Walske said, "The surge of nuclear power production is one of the prime movers in creating the present oil surplus." Nuclear energy accounts for more than 60 percent of the electricity generated in France; more than 50 percent in Belgium; 41 percent in Sweden; 40 percent in Switzerland; 37 percent in Finland; and 34 percent in West Germany.

● **The People's Republic of China** has awarded two contracts worth approximately $9 million to C-E Refractories, a unit of Combustion Engineering, to provide technology, equipment and operator training for two new refractory manufacturing plants. Combustion Engineering also said it signed an agreement with the Chinese to provide components for two coal-fired steam generators that are being designed and manufactured under a long-term technology transfer agreement.

● **The Soviet Union** will allow international inspectors access to two of its nuclear reactors, according to *The New York Times*. The newspaper reported that its sources said the visits by experts from the International Atomic Energy Agency would take place in August. Inspectors were expected to look at two Soviet pressurized water reactors to make sure they are being solely used to generate electricity. *The New York Times* said it would be the first time the Soviets ever allowed inspections of its nuclear installations by outsiders.

● **France's** 1,200 MW Super-Phenix 1 fast breeder reactor will reach criticality by September 15. The Atomic Industrial Forum reports that technicians loaded fuel for the reactor in early August. The breeder, which is being built by an international consortium at Creys-Malville in southern France, is expected to be connected to the French power grid by January 15.

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Some customers of Georgia Power will soon be able to select their own electric rates and level of electric service through their own television sets during a test of a new videotext system.**T/D** 24

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

U.S., China agreement . . . from page 1

enough agreement on the weapons transfer clause. However, he believes the agreement will be passed.

During a July 31 hearing on the agreement before the House Committee on Foreign Affairs, Secretary Herrington testified that strong ties between the U.S. and China will "enhance our mutual goal of a strong nuclear nonproliferation regime."

No proliferation risk

Speaking to the nonproliferation question, Herrington said, "We are convinced that there is no significant, proliferation risk in the agreement...and that it will, in fact, provide important benefits in decreasing this risk."

He told the committee members that China recently joined the International Atomic Energy Agency and is clearly committed to nonproliferation. In his testimony, the secretary declared the agreement does not call for any cooperation that is considered sensitive from the standpoint of nonproliferation.

Herrington told the committee that "cooperation in the sensitive areas of the nuclear fuel cycle—including reprocessing technology—is not contemplated under the agreement. Any such transfers would require amendments to the agreement and would therefore be subject to separate review by the Congress."

According to the energy secretary, the agreement "precludes any use of military or explosive use of items..., no material...may be re-exported without prior U.S. consent...(and) prior mututal agreement is required before China can reprocess, enrich or otherwise alter any material subject to this agreement..."

Further congressional hearings were expected to be held sometime in September, according to a staffer of the House Foreign Affairs Committee.

Callebaut feels the pact can only be beneficial for U.S. companies. "American companies are going to get their share of the $6 billion," he assured.

All of the major U.S. nuclear reactor suppliers were pleased with the agreement and anxious to start negotiating with the Chinese.

Combustion Engineering Senior Vice President Shelby T. Brewer described the pact as "a step forward in our nation's revitilization of its leadership position in international nuclear commerce."

In a prepared statement, Brewer said C-E is hopeful Congress will pass the accord.

Potential opportunity

Babcock & Wilcox Vice President and General Manager Charles Pryor stated, "B&W forsees this agreement as a potential opportunity to provide the Chinese with commercial nuclear technology in areas such as equipment, components and services."

Pryor added that B&W "would welcome the opportunity to offer our technology to this market."

A Westinghouse spokesman said, "While U.S. companies will be entering the market late and against strong international competition, the potential benefit to the U.S. in both jobs and improving the trade balance are large."

According to Westinghouse, a new plant order would mean as many as 4,000-5,000 jobs over a five to six year period and up to a $1 billion contribution to relief of the trade imbalance.

The spokesman said Westinghouse is concerned about the head start other countries have had in negotiating with the Chinese.

"It's an uphill struggle," admitted the spokesman, "but this allows us to get in the game."

General Electric's Nuclear Operations division said in a prepared release, "GE has held a number of general discussions with the Chinese in the past. The agreement will now permit us to conduct future talks on a more specific basis. We will be able to better define the opportunities that are available to U.S. firms in the areas of hardware, software and technology exchange programs."

The nuclear cooperation agreement also is expected to open doors to American architect/engineering firms, constructors and consultant companies.

In his congressional testimony, Herrington pointed out that the advantages of the agreement are not limited to nuclear energy. He said many U.S. companies will be competing for other energy business in China, like the estimated $10-15 billion Chinese hydroelectric market.

While in the U.S., the Chinese delegation toured the New York Power Authority's Niagara Power Project, DOE's Fermi National Accelerator Laboratory and Commonwealth Edison's Braidwood nuclear plant.

SERC administrative manager honored

HOLIDAY INN
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AIRPORT NORTH

William R. Brownlee (l), administrative manager of the Southeastern Electric Reliability Council since 1971, and former Chairman of Southern Services, Inc., receives certificate of appreciation from E.A. Adomat, SERC chairman and executive vice president of Florida Power & Light. Before assuming administrative responsibility for SERC, Brownlee was an early proponent of reliability planning and was instrumental in the development of area-to-area reliability agreements in 1965, formation of the North American Electric Reliability Council in 1968 and organization of SERC in 1969. Upon retirement next January 31, he will become director emeritus of SERC.

Editorial

T&D Maintenance Management seminar could be a model for industry meetings

After 25 years of monitoring electric utility industry developments and attending industry meetings and conferences, it's hard to really become enthused about another meeting program. Maybe it's age that causes the jaundiced eye, or maybe it's because fewer and fewer things are really unusual, new and worth getting enthused about. But, there are exceptions. There's something quite special about the T&D Maintenance Management workshop—the 10th annual, which will be hosted by Salt River Project in Scottsdale, AZ early next month.

The T&D MM seminar is no high-level meeting of utility executives, where the accent is evenly given to party-line rhetoric and socialization. Nor is it like so many technical "conferences," that may fill up two days with formal presentations around only one or two strong reports to justify members' attendance.

Instead, the MM seminar is a true workshop, with the heavy accent on exchange of useable information, the kind attendees can put to work. It is organized, planned and conducted by and for mid-level managers responsible for T&D system maintenance. It exists without the financial support of a larger organization nor the kind of top management backing that accrues to technical committee activities of those larger regional and national organizations.

In other words, it's a meeting that stands or falls on the value of the information exchanged. No half-day sessions with half days of golf. After the opening day, which will involve inspection tours of four Salt River Project T&D operations, each of the following two days of the meeting is crammed with the kind of information participants can take home and put into action. Some twenty-eight subjects will be presented and discussed. Even coffee breaks and lunch periods are working times. That's when a "swap shop" is conducted to allow participants hands-on exposure to specialized tools, equipment, gadgets and other unique items and ideas members have developed to simplify and improve maintenance operations.

When MM seminar participants return home, they will have gone through the mental equivalent of having run two mini-marathons. They'll be tired. But they'll also be primed to tackle their regular jobs with new perspective and new mental tools. The T&D Maintenance Management seminar is one where participants come away with far more than a dollar's worth of useful information and ideas for each dollar their utility spent for their attendance. That's a lot more than many....even most....industry meetings provide.

Who will judge the judges?

In a recent signed article in *The Wall Street Journal*, Alfred Kahn, former state and federal regulator and now a university professor, decried current regulatory practice, which he says is based on the coin-flip philosophy of heads the consumer wins and tails the utility investor loses. In good times commissions limit how much a utility can earn on its successes, normally to a level well-below what non-regulated enterprises would return to shareholders, with the excess flowing back to consumers in the form of rate reductions. Then in bad times, such as when confronted with the several billion-dollar cost of a new nuclear plant, commissions rule that shareholders must bear the burden of the utilities' failures. This "no win" situation, he says, is based on the view of current commissions that customers should not pay for facilities (especially expensive nuclear plants) that are not "used and useful." Defining prudency, as the used and useful concept does, in effect, on the basis of hindsight and then applying it only to failures is to expropriate shareholder dollars, he says, and investors won't stand still for that very long.

The outcome of the above, unless commissions exhibit some turnaround in philosophy, can only be increasingly poorer electric service, brownouts, more and longer outages, and still higher rates. Ultimately, customers pay for the full cost of electric service, directly or indirectly. Short of government takeover, there is no other source. Failure to recognize this simple economic fact of life is but to hasten the day of reckoning. And when it comes, the role of state regulatory commissions must be considered as a *primary cause*.

Robert A. Lincicome, EL&P Editor-in-Chief

Letters

Fulfilled prophecy

EL&P's August "Urge to merge" editorial opened by reminding of prevailing 'bad because big' public perceptions of electric utilities. This drives me to cite the following quotation that I face daily as it hangs on the office wall before me:

> *Only one danger confronts us: that danger is that the growth of our industry will outrun public understanding, and the people will come to see and fear our size, without understanding our service.*

I wonder if Mr. Owen D. Young, then retired chairman of the General Electric Company, knew just how prophetic these words would be when they were spoken in 1925.

Peter Kushkowski
Executive Assistant
Information Resources Group
Northeast Utilities

Free electric supply market

In response to Mr. Ajat Goyal's letter in the June '85 issue of *EL&P* regarding a "free market" supply system for the sale of electric power, serious consequences exist for the homeowner and industry alike.

Mr. Goyal states that "Homeowners could choose from any reasonable number of energy suppliers servicing their area" and "the power could come from any type of plant, any distance." But who would be able to purchase power generated at a hydroelectric facility that has the lowest cost of generation and therefore the lowest cost to the consumer for basic power? How would buyers be selected up to plant capacity? Would industrial users, with their high usage and therefore greater buying power, be given preferential treatment? These are but a few of the problems in just obtaining electric power. Buyers of 'long distance' power should be charged a surcharge for line losses on a kilowatt-per-100-miles basis, thereby incurring a truer energy usage cost that then would be added to the T&D surcharge.

"The organization that is best able to deliver electric power at lowest cost should be rewarded; the inefficient would die their (un)natural deaths...," states Mr. Goyal. In a choice of "any plant, anywhere," obviously consumers would choose the lowest cost available to them. But what will happen to spinning reserve and peak capacity when the inefficient (plants) are gone, having died 'their (un)natural deaths.'

Perhaps Mr. Goyal would be the first to volunteer to be load shed from the T&D system to reduce peak demand. Most utilities attempt to achieve a balance of efficient generation available to them with the plants they own using a combination of newer, more efficient units as base load and older, less efficient units to operate as load followers to give the consumer the best available cost for his dollar.

What Mr. Goyal really is suggesting is parallel to what the FTC did to AT&T and everyone knows what that has done to our phone bills and service.

Thomas G. Proios
Professional Engineer
Woodhaven, MI

Roberts ok'd for second NRC term

WASHINGTON, D.C.—Thomas M. Roberts was confirmed by the Senate July 8 to serve a second five-year term on the Nuclear Regulatory Commission.

Roberts was first sworn in as a member of the NRC on August 3, 1981.

President and CEO

He served as chief executive officer and president of the Southern Boiler & Tanks Works, Inc. from 1969 to 1978. Roberts also has been an underwriting member of Llyod's of London and a director of Boyle Investment Company.

Next term to expire

NRC spokesman Robert Newlin said that NRC Chairman Nunzio Palladino's term will expire next year.

Top 100 correction

Consumers Power Co.'s J.H. Campbell unit three should have been listed with the 20 most efficient generating units in the article on operations at the 100 largest investor owned utilities in the August issue of *EL&P*. The table on pages 18 and 19 should have listed Campbell 3 in a tie for 4th place with a heat rate of 9110.

Coal consumption by American Electric Power listed on page 17 and in the table on page 18 should have been 38,351,000 tons, a 5.4 percent increase over 1983.

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Coal production to soar over next 10 years

WASHINGTON—Utility fuel buyers can look for a thriving coal industry over the next 10 years supplying all the coal they need with little increase in real minemouth prices, according to the latest forecast from the Department of Energy's Energy Information Administration.

Coal industry production is expected to climb from about 900 million tons in 1985 to 1.06 billion tons in 1990 and 1.22 billion tons in 1995—a growth rate of about 3.3 percent per year which is expected to roughly parallel the growth in electricity demand.

Electric utilities will dominate the coal market even more in 1995 than they do now, says EIA. Utilities now account for about 80 percent of coal consumed in the U.S., up from 72 percent in 1975. By 1995 utilities will account for a whopping 86 percent of U.S. coal consumption.

Coal supply should be plentiful and reliable: "The coal industry is expected to produce all the coal demanded by domestic and foreign consumers through 1995...Coal resources are abundant, and considerable excess production capacity exists."

Overall coal production and consumption trends are shown in Table 1. The utility fuel consumption outlook is shown in Table 2.

Utility domination of the coal market results from steady growth in utility consumption while the other sectors are expected to show little growth. Chief casualty is the metallurgical market. In the last 10 years coking plant consumption has fallen in half. Since 1980 22 coke plants have shut down as steel consumption has declined and foreign competitors have taken an increasing share.

EIA expects little growth in the coal synfuels industry. It says the only major plant expected to be in operation in 1995 is the Great Plains coal gasification plant which now faces abandonment (see page 1 story).

Modest growth in exports is expected although the 106 million tons forecasted for 1995 is still short of the record 113 million tons exported in 1981. The export market could fluctuate widely, the EIA report warns, because it is so sensitive to exchange rates, government policies, and future events like the Iranian revolution that triggered the last burst in demand for U.S. steam coal.

The industrial market is also expected to show modest growth in coal demand over the next 10 years.

Utility growth accounts for almost all the growth in coal output, however. Utility consumption is expected to grow by almost 300 million tons per year, from 660 million in 1985 to 950 million in 1995. Coal industry production is expected to grow by 330 million tons per year.

Looking at utility output in Table 2, it is clear that coal accounts for the bulk of growth in utility generation over the next 10 years. Output is expected to be 12 quads per year more in 1995 than in 1984. Half that growth is supplied by coal and one-fourth from increased nuclear output. Slight increases in oil and gas consumption account for the rest.

Coal's share of electricity output is expected to stay fairly constant at about 56 percent, with nuclear's increasing share offsetting the declining share for natural gas and oil.

Increased coal consumption will take place in the 64 GW of new coal fired capacity under construction or definitely planned for operation by 1995, as shown in Table 3.

EIA looks for a two-phase impact on coal demand from these new plants. The first phase will see a boost in consumption of low- and medium-sulfur coal between now and 1990. That's because the new plants coming on line were licensed under the 1971-1978 federal emission control standards that allowed use of low-sulfur coal as a compliance method. In the second phase, from 1990 to 1995, there will be a shift away from low-sulfur coal as plants built under the post-1978 standards requiring scrubbers on all plants start operating.

It should be noted that coal's prospects are even better after 1995 because of the end of the nuclear plant pipeline. All nuclear plants ordered since 1975 have been cancelled and the backlog of pre-1975 orders should be completely built out by 1995. That means nuclear output will peak then and its share of a rising electricity generation market will begin falling. With nuclear as coal's only major competitor for market share, the coast will be clear for coal after 1995.

It should be noted that the EIA forecast is substantially higher than that of the National Coal Association, the coal industry's trade group. NCA says 1995 coal consumption will be only 995 billion tons.

NCA's prediction is the lowest of the major forecasts, however. Major private forecasters Data Resources, Inc. and Chase Econometrics Associates, Inc. are in substantial agreement with the EIA prediction. DRI sees 1995 coal consumption at 1.072 billion tons and Chase puts it at 1.147 billion tons. NCA, however, is much more optimistic about exports than EIA, estimating that 1995 exports will total 133 million tons.

TABLE 1
U.S. COAL SUPPLY AND DISPOSITION, 1975-1995
(Million Short Tons per Year)

	History		Projections		
Supply and Disposition	**1975**	**1984**	**1985**	**1990**	**1995**
Production	655	890	899	1,057	1,221
East	544	584	582	650	731
West	111	306	317	407	490
Net Exports	65	82	72	91	106
Net Storage Withdrawals	-32	-29	15	-8	-6
Total Supply	568	781	842	957	1,110
Consumption by Sector					
Residential and Commercial	9	9	8	7	7
Industrial	64	72	77	89	98
Coking Plants	84	44	46	51	49
Electric Utilities	406	664	709	805	951
Synthetic Fuels	0	2	5	6	6
Total End-Use Consumption	563	791	843	958	1,110

Source: "Annual Outlook for U.S. Coal," May 1985, EIA

TABLE 2
U.S. ELECTRIC UTILITY FUEL CONSUMPTION, 1975-1995
(Quadrillion Btu per Year)

	History		Projections		
Fuels	**1975**	**1984**	**1985**	**1990**	**1995**
Coal	8.8	14.1	14.9	16.9	19.9
Oil	3.2	1.3	1.2	1.3	2.0
Natural Gas	3.2	3.2	3.3	3.4	3.9
Nuclear	1.9	3.5	4.1	6.3	7.1
Other	3.3	3.9	3.1	3.3	3.4
Total	20.4	26.0	26.7	31.2	36.3

Source: "Annual Outlook for U.S. Coal," May 1985, EIA

TABLE 3
COAL-FIRED EXISTING CAPACITY AND CAPACITY ADDITIONS
BY REGION, 1985-1995
(Gigawatts)

Region	Existing Capacity 1984	Capacity Additions 1985-1995
New England	1.6	0
New York/New Jersey	5.1	0
Middle Atlantic	43.0	5.2
South Atlantic	75.8	18.0
Midwest	84.4	6.3
East of the Mississippi	209.9	29.5
South West	30.2	19.7
Central	27.2	1.4
North Central	19.7	5.8
West	7.0	5.9
North West	1.9	2.1
West of the Mississippi	86.0	34.9
U.S. Total	296.0	64.4

Source: "Annual Outlook for U.S. Coal," May 1985, EIA

Bring back the gas-fired plant option, MIT researchers argue

VANCOUVER, BC—Base-loaded, natural-gas fired, combined-cycle generating units should be put back in the utility capacity planner's arsenal, according to an analysis made by two researchers at the Massachusetts Institute of Technology's Laboratory for Electromagnetic and Electronic Systems.

In a presentation made at the recent IEEE summer power meeting Richard Tabors and Daniel Flagg said their study shows electricity costs could be reduced by 13 percent if natural gas could be used as a fuel for base-loaded power plants coming on line after 1990.

Noting that federal law currently prohibits use of natural gas in new plants, the researchers said, "This decision was based on what now appear to be faulty assumptions concerning gas availability and clearly on faulty assumptions concerning fuel economics."

If utility gas use were unconstrained, 1995 natural gas consumption in the U.S. would increase by only 20 percent, they contended. Utility gas consumption would not quite double over the currently projected level, according to the analysis.

Tabors and Flagg used the Electric Generation Expansion Analysis System developed for EPRI by MIT and Stone & Webster to analyze utility generation options in the period 1990-2004. They studied expansion in the six regional utility system models developed by EPRI for scaled-down modeling of generating systems in the U.S.

Most attractive options

The researchers allowed the program to choose among the five "most attractive" generation options: a 1000-MW PWR (at a capital cost of

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Volume 63, Number 10
October 1985

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

©TECHNICAL PUBLISHING

Nuke-to-coal switch nixed in Texas, still alive in Ohio

The South Texas Project, one of the two nuclear projects being considered for conversion to coal, looks like it's going to continue as a nuclear plant. The other one, Zimmer, is still pursuing the conversion concept.

Conversion of South Texas Project to coal was declared economically unfeasible by a study just completed by Sargent & Lundy. The study was commissioned last fall at the insistence of the Austin, Texas Electric Dept., one of the four owners.

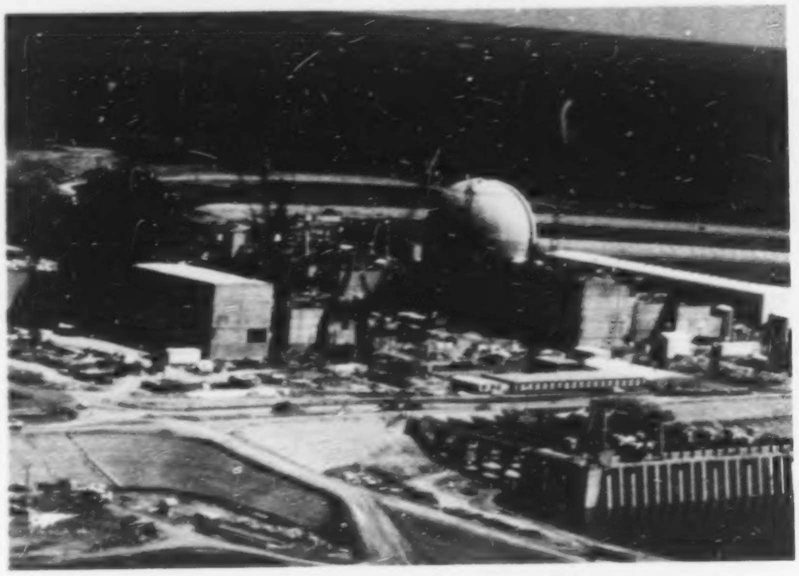
A spokesman for lead STP owner, Houston Lighting and Power, said his company's view that conversion never was viable has been confirmed by the study. "The issue is closed," he said.

That opinion was shared by a spokesman for San Antonio City Public Service who said, "The results are in and that's that."

The twin-unit STP is currently under active construction.

Progress at Zimmer

Meanwhile, a settlement conference got underway at the Ohio Public Service Commission to see if an agreement could be worked out on the Zimmer conversion proposal. The main issue there is the accounting treatment of the investment in the 800-MW single unit project that was cancelled in 1984.


Owners of the nearly complete but cancelled Zimmer nuclear project want to convert it to coal.

The owners requested that interested parties hold the conference to hammer out a deal rather than go to a PUC hearing. They hope all parties involved can agree on a package prior to taking it to the full commission.

W. H. Dickhoner, president of Cincinnati Gas & Electric, Zimmer's lead owner, recently told New York security analysts, "...we expect that a stipulation in this case would determine what portion of the costs of the existing plant will be disallowed from rate base. We are optimistic that the settlement conference can reach a conclusion in an expeditious manner, so that a stipulation in the case can be presented to the commissioners for approval early this fall."

The conference is being attended by the owners, the Ohio PUC staff, the Ohio Consumers Counsel, and representatives of some large industrial electric customers. Several meetings have been held but no details of results have been announced.

Zimmer was cancelled at the 97 percent completion point with about $1.7 billion invested. The cancellation stemmed from a dispute with the Nuclear Regulatory Commission over construction quality assurance. The owners said it would have cost $1.5 billion more to finish the plant, which they refused to do.

The owners commissioned Ebasco and National Economic Research Associates to study the viability of converting it into a coal-fired plant.

Last summer the owners reported that the study results were favorable and that they would proceed with engineering on the coal conversion. The plan is to use about 45 percent of the investment in the nuclear plant in a coal plant. Usable nuclear facilities are chiefly in the back end—the steam turbine, generator, cooling tower, etc.

An additional investment of $1.7 billion will provide a 1300-MW coal-

Continued on page 3

MSU and operating companies struggling to stay afloat

Don Minner
Associate Editor

NEW ORLEANS—Two of the four financially-troubled subsidiaries of Middle South Utilities can breathe a little easier now.

Both Arkansas Power & Light (AP&L) and New Orleans Public Service (NOPSI) were granted limited rate increases by their respective public utility commissions in early September in order to help pay the utilities' portions of the Grand Gulf-1 nuclear plant.

AP&L, NOPSI, Mississippi Power & Light (MP&L) and Louisiana Power & Light (LP&L) have been struggling to make their monthly payments for their respective portions of the plant, which went into service July 1.

Middle South Energy, an MSU subsidiary, owns 90 percent of Grand Gulf-1.

The financial situation for the utilities became so dire in late August that all of the operating companies stopped payment of their common dividend to MSU.

That prompted MSU to declare Aug. 29 that it would not be able to pay out its common stock dividend. MSU spokesman Cyril Guerrera said it was the first time in 144 consecutive quarters that a common stock dividend had been missed.

MSU's Board of Directors stated, "...until greater progress is made on the various legal and regulatory fronts with respect to emergency or full rate relief for the System operating companies regarding their Grand Gulf payments, we believe omission of the dividend of 44.5 cents for the third quarter is the most prudent course of action."

The utility has a total of approximately 400,000 stockholders.

All four operating companies have battled back and forth with their various regulatory bodies and state and federal courts during the past year in efforts to obtain rate relief to pay for the nuclear unit.

AP&L gets relief

In early September, the Arkansas Public Service Commission voted 3-0 to approve an agreement that settles AP&L's rate case and resolves all open issues involved in thirteen different regulatory and court cases.

AP&L spokesman Charles Kelly explained that negotiations had been going on for several weeks between the utility, the state attorney general, the PSC staff and a group of AP&L's largest industrial customers.

All of the parties agreed to terminate various other proceedings in addition to the rate case, including seven other cases before the PSC and five cases in state or federal court. Also, the intervenors agreed to withdraw their opposition to three AP&L financing requests filed with the Securities and Exchange Commission.

According to terms of the ten-year phase-in, the utility will receive a $45.8 million general rate increase and $35.5 million for its share of Grand Gulf during the first year.

Kelly said the settlement recognizes various accounting procedures that permit AP&L to use the sale of securities to help finance its Grand Gulf payments during the early years of the plan.

According to Kelly, AP&L had reached its credit limit with 60 banks.

AP&L's monthly Grand Gulf payment amounts to approximately $30 million. The utility owns 36 p[illegible]ent of the unit.

"This doesn't take us back to business as usual," admitted Kelly. But, he added, that on the whole "it is a fair and equitable resolution."

Emergency aid for NOPSI

Meanwhile, in New Orleans, the city council voted Sept. 5 to allow NOPSI emergency rate relief of $28.3 million over the next ten months, far short of its $118 million request.

NOPSI spokesman Bill Tregre said the utility has a monthly payment of

Continued on page 7

Slow second quarter growth blamed on milder weather

BARRINGTON, IL—Milder than usual weather contributed heavily to disappointing revenue and earnings growth for many electric utilities in the second quarter.

According to an *EL&P* random survey of 29 electric companies (see table) and interviews with electric utility analysts, declines in revenues and earnings were prevalent for the period.

Commenting on the cause of the slow-up, utility analyst Pat Madden, Duff & Phelps, said, "It was the nicest spring we've had in 10 or 11 years."

He said earnings growth and electricity sales were generally down in the quarter.

Electric sales dropped 7.0 percent at Philadelphia Electric. The company attributed it to cooler weather.

Illinois Power, which saw significant decreases in earnings and revenues, said sales of electricity and gas were down.

A 17 percent decline in earnings at Dominion Resources for the period was also blamed on lower kilowatt-hour sales and milder weather.

Gas sales drop

The gas segments of MDU Re-

Continued on page 3

News Briefs

● **Seabrook's** joint owners voted in August to increase funding for the project to a level of $8 million per week. New Hampshire Yankee said the increase from the previous $5 million per week funding level is conditioned on the New Hampshire Public Utilities Commission lifting spending restrictions imposed on Public Service Company of New Hampshire. A decision was expected to be made sometime in mid-September. PSNH is currently limited to contributing no more than its share of a $5 million per week funding level.

● **The Montana Public Service Commission** has announced it will appeal a district court order that overturned its 1984 ruling on Montana Power's Colstrip Unit 3 coal-fired plant. The announcement came shortly after the PSC said it had decided it would not join with Montana Attorney General Mike Greeley in appealing the decision. The MPSC stated that it believes its original decision not to appeal was correct, but feels its knowledge and expertise must be made available in the case if an appeal is pursued by the attorney general. The MPSC had denied the utility any return on its investment in the unit. The district court remanded the order back to the commission for reconsideration. Also in August, the PSC authorized an $80.4 million annual electric rate increase to be phased in over eight years. Montana Power said the increase principally recognizes costs associated with the utility's 30 percent interest in the 700 MW unit.

● **The California Public Utilities Commission** has decided to look into the feasibility of basing payments for the electricity from Pacific Gas & Electric Company's Diablo Canyon nuclear plant on the economic value of the energy produced rather than on the cost of plant construction. California currently uses two different methods for setting the price that utility customers pay for electricity. Under the traditional "cost of service" method, the commission determines which utility costs are reasonable and prudent. The other method, which the PUC is studying for Diablo Canyon, is value-based pricing. Under that method, the commission determines the economic value of the electricity produced without reviewing the producer's costs or operating expenses. PUC President Donald Vial said the PUC's goal "will be to try to find the best method of maintaining the lowest reasonable costs for Diablo Canyon over the 30-year expected life of the plant." Vial said he recognizes that it will be difficult to come up with a value-based pricing formula that is fair to everyone. The commission said that the issue, in a sense, is whether the plant should be viewed as the last California power plant built under traditional regulation, or the first built under the new rules for power generation.

● **Pacific Gas & Electric Co.** was issued a full power operating license August 26 by the NRC's Office of Nuclear Reactor Regulation for its 1,106 MW Diablo Canyon Unit 2.

● **Britain's Central Electricity Generating Board** plans on building a "small family" of pressurized water reactor power plants, according to the London Press Service (LPS). The plan would go into effect if the go-ahead is given to introduce the PWRs at Sizewall in eastern England. LPS reports that a recommendation on the plants is expected to be sent to the UK government by the end of this year. If approval to build is granted, the CEGB explained that it plans to start site work on the 1175 MW plant in September 1986. The project would create approximately 10,000 jobs for seven years. CEGB Chairman Lord Marshall said, "The board has indicated that if it gets consent to build Sizewell B it would like to replicate the design for a small family of similar power stations so as to gain the full economic return from investment in PWR technology." LPS said the CEGB is investigating other potential sites at two existing power plants in North Wales.

● **Atomic Energy of Canada Ltd.**, the Canadian government agency, has signed an agreement with Turkey to construct, own and partially operate a 665 MW CANDU nuclear reactor. *The Wall Street Journal* reported in August that the agency will design the heavy water reactor valued at $1.1 billion, which will be built in southern Turkey. The newspaper said the plant will be 40 percent-owned by Turkey and 60 percent-owned by a consortium, in which Turkey is the major participant. The consortium, which includes NEI Parsons Ltd. and Enka Holding Yatirim AS, will operate the reactor and sell the power to Turkey for the first 15 years. The group then will sell its equity and turn over the plant to Turkey.

● **The National Rural Utilities** Cooperative Finance Corporation (CFC) has had a record year. Reporting on its fiscal year ending May 31, CFC said it recorded a net margin of $32 million with total loans outstanding of $2.78 billion. In 1984 CFC had $27.7 million in margins and $2.68 billion in outstanding loans. CFC stated that its assets at the end of the fiscal year were $3.05 billion compared to $2.84 billion last year. Members' equity and investments in CFC rose to $1.79 billion on May 31, from the previous year's $1.45 billion. Of that amount said CFC, member equity increased from $116 million in 1984 to $142 million at the end of the past year. CFC is owned by more than 900 rural electric organizations.

● **Five Iowa utilities** are investing money in the new Iowa Venture Capital Fund that has been formed to foster economic development in the state. The fund is a limited partnership for making investments in privately held companies. The gas and electric utilities are investing a total of $1.05 million in the venture capital fund. They are Iowa-Illinois Gas and Electric, Interstate Power, Iowa Public Service, Iowa Resources, and Iowa Southern Utilities. The fund's general partners are Jerry M. Burrows and InvestAmerica Venture Group, Inc. The limited partners are Life Investors Insurance Co. of America, Central Life Assurance Co. and Statesman Financial Services, Inc. The partnership is expected to operate for an initial term of 12 years and invest from $10 to $15 million.

● **The Atomic Safety and Licensing Board** ruled in August that Long Island Lighting Company cannot have an operating license for its Shoreham nuclear plant. The ASLB said, "...that there is no reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at Shoreham...". According to the ASLB, LILCO's emergency plan was defective on two grounds. First, said the board, LILCO doesn't have the authority to implement the plan it submitted. Secondly, opposition by New York state and Suffolk County to the plan creates uncertainty as to whether the plan would be workable. LILCO spokesperson Carol Clawson said an appeal is pending with the Atomic Safety and Licensing Appeals Board.

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'Energy Independence' marks 2nd year

New England Electric's coal-fired, coal-carrying ship 'Energy Independence' celebrated its second birthday in August. The vessel has delivered over five million tons of coal. The ship carries domestic coal from ports in Philadelphia, Baltimore, Newport News and Norfolk to New England Electric plants in Somerset and Salem, Mass. The ship's unique self-unloading system allows it to discharge its cargo in 12 hours.

Toledo Edison, CEI merger papers filed

TOLEDO, OH—Documents have been filed with the Securities and Exchange Commission by Toledo Edison and the Cleveland Electric Illuminating Co. requesting approval of their merger.

In the documents, the utilities said that formation of a holding company will enable them in the long term "to achieve benefits of increased financial ability and strength, improved and unified management, efficiencies of operations, better use of the facilities for the benefit of customers, reduced requirements for future generating capacity, improved abilities to utilize new technologies and greater industrial sales diversity."

Name not selected

A name for the new holding company has not yet been selected. As operating companies, Toledo Edison and CEI will retain their names.

Slow 2nd quarter . . .
from page 1

SELECTED SECOND QUARTER EARNINGS	Operating revenues, 1985 (thousands)	Operating revenues, 1984 (thousands)	% Change	Earnings per share, 1985	Earnings per share, 1984	% Change
AZP Group	[illegible]	[illegible]	+18.[illegible]	[illegible]	[illegible]	+17.[illegible]
Central Hudson G&E	117,923	122,464	-3.7	1.03	1.01	+2.0
Central Illinois Pub. Serv.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Consolidated Edison	1,209,270	1,246,040	-3.0	.61	.64	-4.7
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.43	[illegible]
Dominion Resources	608,352	599,341	+1.5	.53	.64	-17.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
FPL Group	1,062,466	967,614	+9.8	.78	.49	+59.2
Green Mt. Power Corp.	[illegible]	[illegible]	[illegible]	[illegible]	.34	[illegible]
Houston Indus.	1,114,373	1,189,523	-6.3	1.30	1.22	+6.6
[illegible]	[illegible]	[illegible]	-14.[illegible]	[illegible]	[illegible]	[illegible]
IPALCO	107,144	108,724	-1.5	.81	.94	-13.8
Iowa-Illinois G&E	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Iowa Resources	97,153	100,651	-3.5	.49	.65	-24.6
KPL Gas Service	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Louisville G&E	144,192	150,716	-4.3	.66	.81	-18.5
MIDWEST Energy	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Minnesota Power	105,370	99,436	+6.0	1.18	1.07	+10.3
MDU Resources	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
NSP	386,900	393,300	-1.6	1.17	1.29	-9.3
Pacific Corp.	[illegible]	[illegible]	+7.6	.77	[illegible]	[illegible]
PP&L	480,432	351,310	+36.8	.48	.59	-18.6
Philadelphia Electric	[illegible]	[illegible]	-2.8	[illegible]	[illegible]	-1.7
Portland General Elec. Co.	165,988	153,363	+8.2	.25	.51	+51.0
Potomac Electric	[illegible]	[illegible]	+17.7	[illegible]	[illegible]	+11.7
PSNM	173,598	109,574	+58.4	.55	.56	-1.8
Puget Power	144,449	136,190	+6.1	.30	.19	+57.9
SCANA	251,487	263,353	-4.5	.60	.59	+1.7
Texas Utilities	1,116,210	1,112,[illegible]	+0.3	1.20	1.22	-1.6

sources, Iowa Resources and KPL Gas Service were affected by the weather. All three said the mild weather caused gas sales to decline.

Mark Luftig, a utility analyst with Salomon Brothers in New York, pointed out that earnings were down for the industry as a whole in the second quarter by three and a half percent.

"The second quarter was pretty much as expected," noted Luftig.

He cited several outstanding performers for the period that included Consumers Power, Montana Power, Public Service of New Hampshire, United Illuminating and Minnesota Power.

Some utilities improved

All was not bad in the quarter however. PacifiCorp reported higher quarterly revenues for its three major segments—Pacific Power, Pacific Telecom and NERCO. Also, the company posted a 22 percent increase in kilowatt-hour sales. Pacific Power said sales to other utilities were "up substantially."

AZP Group Vice President and Treasurer Henry B. Sargent tied his company's earnings increase to higher sales. He pointed out that the company's subsidiary, Arizona Public Service, experienced a very warm spring and has continued to add customers at an annual rate of nearly five percent.

Earnings for the second quarter rocketed almost 58 percent at Puget Power. The utility said a recent rate increase, increased sales and a strong cost-containment program were reasons for the improvement.

Louisville Gas & Electric Co. and Central Hudson Gas & Electric both realized higher sales in the quarter.

Rate increases aided Green Mountain Power Corporation's and FPL Group's second quarter financial statements.

E.F. Hutton's Raymond Moore said the market price for the electric industry as a whole was up 11 percent in the second quarter. "The group did pretty well," he contended.

Moore compared the performance to the Standard & Poor's 400 Index of industrials which rose only four percent. It was defensive environment in the second quarter and Moore said that means investors go to utilities.

Earnings will be flat

He predicts that earnings growth over the next few quarters will be flat or down. Moore said many utilities are not able to justify large rate increases. He doesn't think construction activity will pick up and says financing will be "miniscule" in the next few years.

"As a whole," noted Madden of Duff & Phelps, "the industry's problems are becoming more manageable."

But, he said he has a feeling that the third quarter may not look great. Madden mentioned that most of the country has experienced a mild summer, resulting in lower sales.

Luftig predicts that second half earnings of utilities will increase four percent.

"The whole of the industry is an improving pattern," declared Robert Burke of Moody's Investors Services.

Burke noted that many utilities are completing construction programs and gradually improving their finances. He said construction expenditures are easing off, internal cash is accumulating and external financing is declining.

Burke pointed out that Moody's upgraded bond ratings of several utilities in the second quarter. They included Central Hudson Gas & Electric, Niagara Mohawk Power, San Diego Gas & Electric, Tucson Electric and Union Electric. He explained that all the companies generally have reasonable regulation and are nearing the completion of construction. Burke said Moody's expects earnings to improve at the utilities.

Nuke-to-coal switch . . . from page 1

fired plant with a design similar to the basic design now being used by AEP, one of the Zimmer owners.

The plan calls for AEP Service Corp. to design and build the coal plant. It is currently working on engineering. Specs for the sulfur dioxide scrubber and precipitator have been issued to prospective suppliers who have been invited to submit bids.

The key question is: how much of the $1.7 billion already spent on the nuclear plant will be allowed into the rate base for the completed coal-fired plant. A commitment to full-scale work on the project awaits that determination.

The owners are hopeful that enough will be allowed to make the venture attractive. No specific target has been set, but, as mentioned, a working figure of 45 percent has been discussed.

Said Dickhoner to the New York analysts, "We are still planning to begin major construction in 1987 with completion and operation of the coal conversion scheduled for 1991."

South Texas

The situation is substantially different at the South Texas Project because it's still under construction. There are two 1250-MW units: Unit 1 is 84 percent complete and unit 2 is 55 percent finished. Unit 1 is slated for operation in 1987 and unit 2 in 1989. The owners currently estimate that STP will cost $5.5 billion.

A disagreement among the owners about project schedules led to the full-scale Sargent & Lundy conversion study. Completed last August, the study concluded, "The conversion of STP to coal firing is judged to be technically possible, but economically not justifiable."

An economic analysis compared the generating cost of electricity produced in a coal plant with the costs of electricity from the completed nuclear plant (which, it should be noted, was not an option at Zimmer.) The nuclear case was the lower-cost option for all the owners. The study found that the present worth of lifetime savings for all owners for the nuclear case is $3.5 billion. The analysis assumes that all nuclear investments are recovered.

Sargent & Lundy estimated that $1.5 billion of the $3.9 billion already spent at South Texas Project could be used in a coal plant. The study showed it would require an additional $3.7 to $4.8 billion to accomplish the conversion. The completed coal plant would have had up to 1300-MW more generating capacity than the 2500-MW nuclear station under construction.

Said Jamie Axtell, manager of generation and environmental planning for San Antonio City Public Service, which oversaw the study, "We believe the preponderance of evidence clearly shows that converting the STP to a coal plant is definitely not in the best interests of utility ratepayers. Besides, construction of the STP as a nuclear plant continues to move forward in steady fashion."

The most economical coal conversion plan called for adding supercritical, reheat coal-fired topping cycles. Net plant heat rate was estimated to be 9800 Btu/kWh.

The report said there were intangible factors that could make the conversion even more costly than estimated. For example, in order to use the large turbine-generators in place for the nuclear plant, the topping cycles would require large, multiple coal-fired boilers. "The complexity of the component installation," said Sargent & Lundy, "unlike any previous coal-fired plant, could cause degraded reliability beyond the numerical predictions in this report, as well as higher operating and maintenance costs than those reported herein." The equivalent forced outage rate estimated for the reheat topping cycle was 29 percent.

"The major steam turbine components, particularly those associated with the reheat cycles, would see operating conditions unlike those of a standard cycle," said the report, adding, "The reheat cycles would require a one-of-a-kind turbine design."

TMI-1 restart put in holding pattern

HARRISBURG, PA—With a go-ahead from a federal appeals court on August 27, GPU Nuclear seemed to be on the verge of restarting its Three Mile Island Unit 1.

That is until two days later when Judge Collins Seitz of the Third U.S. Circuit Court of Appeals continued his original stay of the Nuclear Regulatory Commission's May ruling allowing the plant to be restarted.

Court ruled 2-1

A three judge appeals court ruled 2-1 that the NRC had heard enough evidence before granting the utility permission to operate the unit. While GPU Nuclear was awaiting approval from the NRC to start the unit, Judge Seitz continued his original stay on August 29 to allow petitioners time to file appeals of the decision.

Petitioners opposed

Petitioners opposed to restart include The Union of Concerned Scientists, Three Mile Island Alert, and Pa. Gov. Richard Thornburgh.

GPU Nuclear spokesperson Lisa Robinson said, in early September, that the petitioners are asking that the case be heard by the full Third U.S. Circuit Court of Appeals.

In the meantime, noted Robinson, GPU Nuclear will be asking that the stay be lifted.

She said unit 1 is being kept in a "hot standby" condition.